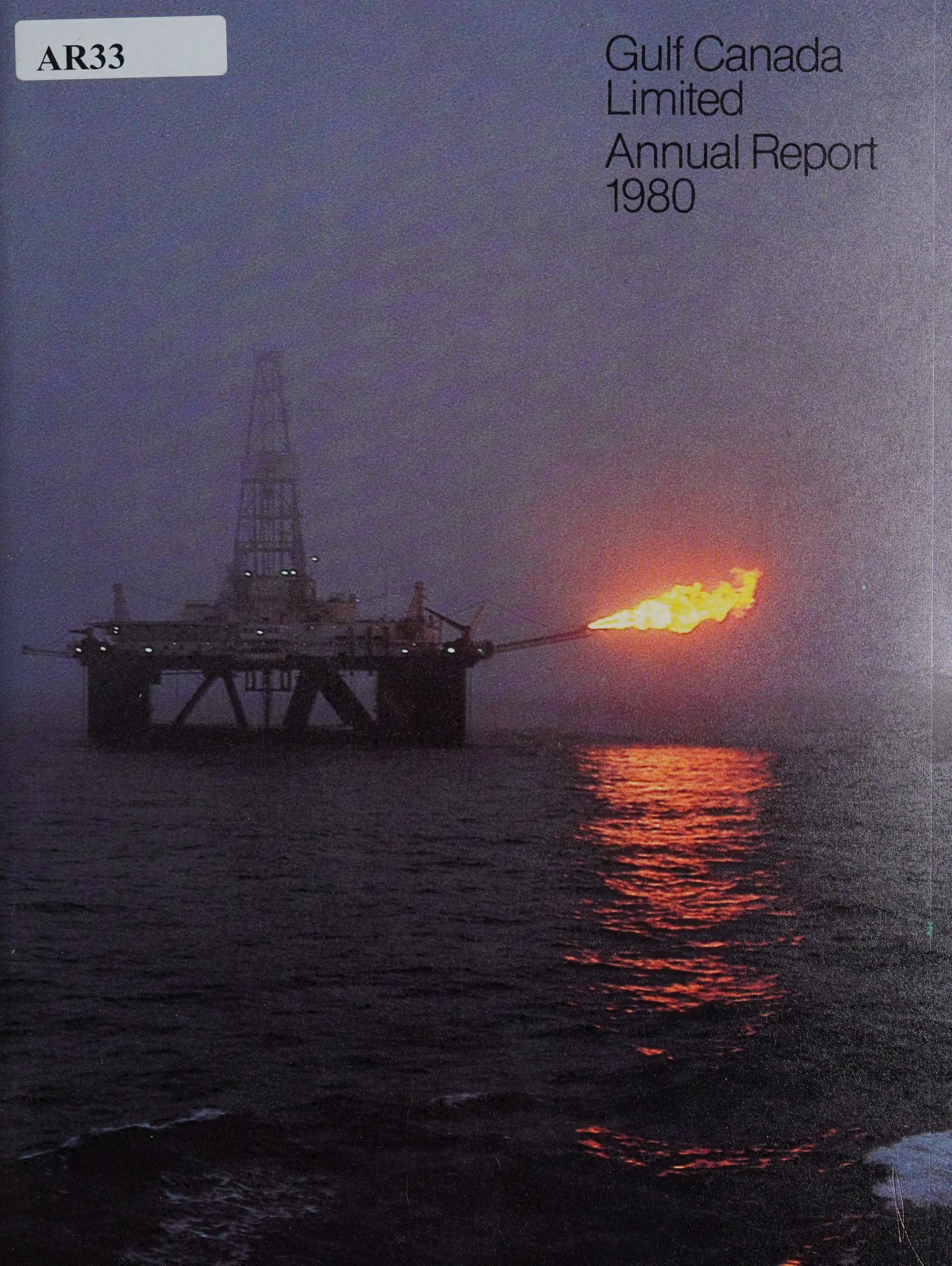
Gulf Canada Limited

Annual Report 1980



Corporate Profile

With almost 40,000 shareholders and 10,900 employees, Gulf Canada Limited is one of Canada's largest fully-integrated oil companies. Founded in 1906 as The British American Oil Company Limited, its assets now total $3.7 billion. Gulf Canada Limited consists of a corporate management company located in Toronto, and upstream and downstream divisions.

Gulf Canada Limited:
The management company has responsibility for developing overall corporate strategic direction, basic policies, performance objectives, controls and measurement criteria for application throughout the Corporation.

Gulf Canada Resources Inc.:
Headquartered in Calgary, this upstream subsidiary is responsible for exploration and production activities. At the end of 1980, GCRI had an interest in 6,649 oil and gas wells in Canada. It participated in the first major discoveries in the Beaufort Sea and off Canada's east coast, and in the Syncrude Athabasca oil sands project. GCRI operates seven natural gas processing plants and has varying interests in 80 other gas plants and field gathering facilities.

Gulf Canada Products Company:
The downstream division, headquartered in Toronto, is responsible for refining, marketing, chemicals, and supply and transportation operations. It operates five refineries and two asphalt plants with a total daily crude oil processing capacity of 48,500 cubic metres—approximately 13 per cent of Canada's refining capacity. Selling products throughout Canada, it accounts for approximately 15 per cent of the country's refined product sales. Chemical operations include a major interest in a Quebec-based petrochemicals consortium.

Contents

Annual Meeting

The annual meeting of shareholders will be held in the Concert Hall of the Royal York Hotel, Toronto, at 2:00 p.m. EST, Thursday, April 23, 1981.

The Cover:

Three hundred kilometres east of Newfoundland on fog-shrouded Grand Banks, operators run production test on Hibernia B-08 well. Located four kilometres north of the Hibernia P-15 discovery well, the B-08 step-out is the third successful well drilled on the structure.

Metric conversion table

Measurement	Traditional to metric	Metric to traditional
Length	1 mile = 1.609 34 kilometres (km)	1 km = 0.62137 mile
	1 foot = 0.304 80 metre (m)	1 m = 3.28084 feet
Area	1 acre = 0.404 69 hectare (ha)	1 ha = 2.47103 acres
Volume	1 gallon (Can.) = 4.546 09 litres (L)	1 L = 0.21997 gallon (Can.)
	1 barrel = 0.158 99 cubic metre (m^3)	1 m^3 = 6.28970 barrels
	1 MCF = 28.173 99 cubic metres (m^3) (natural gas)	1 m^3 = 0.035494 MCF
Mass	1 pound = 0.453 59 kilogram (kg)	1 kg = 2.20463 pounds
	1 long ton = 1.016 05 tonnes (t) (2,240 pounds)	1 t = 0.98420 long ton
	1 short ton = 0.907 19 tonne (t) (2,000 pounds)	1 t = 1.10232 short tons

International System of Units (SI) conversion factors used by Canadian Petroleum Association in its statistical handbook effective January 1, 1979.

Conversion to Metric

During 1979 the Canadian petroleum industry commenced using the International System of Units, commonly called the metric system, to report figures related to length, area, volume and mass.

All figures, graphs and tables given in this year's Annual Report are in metric measure.

10K Report Available

A copy of the 1980 Annual Report on Form 10K to be filed with the United States Securities and Exchange Commission may be obtained upon request. Requests should be directed to: Public Affairs Department, Gulf Canada Limited, 130 Adelaide Street West, Toronto, Ontario M5H 3R6.

Rapport annuel

Ce rapport est disponible en français sur demande.

Financial Highlights

	1980	1979
	(millions of dollars)	
Net revenues	**4,130**	3,058
Net earnings	**380**	288
Dividends declared	**93**	68
Government royalties and taxes	**1,287**	928
Funds generated from operations	**542**	410
Capital and exploration expenditures	**572**	410
Total assets	**3,692**	3,295
Long-term debt	**315**	333
Shareholders' equity	**1,926**	1,639
Return on shareholders' equity	**21.3%**	18.8%
Return on capital employed	**15.3%**	13.3%
Per Share Data*		
	(dollars per share)	
Net earnings	**1.67**	1.27
Dividends declared	**0.41**	0.30
Funds generated from operations	**2.38**	1.80
Shareholders' equity	**8.47**	7.20
Price/earnings ratio	**14**	18
Operating	*(thousands of cubic metres per day)*	
Gross production		
—Conventional crude oil and natural gas liquids	**20.6**	21.5
—Synthetic crude oil	**1.7**	1.1
—Natural gas produced and sold *(millions)*	**8.9**	11.0
Crude oil processed by and for the Corporation	**46.1**	50.6
Sales		
—Petroleum products	**42.7**	42.9
—Chemicals *(millions of kilograms per day)*	**1.3**	1.4
Net Proved Reserves	*(millions of cubic metres)*	
—Conventional crude oil and natural gas liquids	**35.6**	38.6
—Synthetic crude oil	**16.4**	17.0
—Natural gas *(billions)*	**50.4**	51.9

Market Value of Common Shares*	**1980**	1979	1978
		(dollars per share)	
Toronto Stock Exchange—High	**38⅝**	25	7½
—Low	**19⅞**	7⅛	5⅛
—Close	**23⅞**	22⅜	7⅜
Shares traded *(thousands)*	**188.1**	123.4	87.1

*Restated to reflect five-for-one split of common shares effective May, 1980.

Report to the Shareholders

The 1980s could go down in history as "the decade that might have been" if the National Energy Program is not further amended and federal-provincial differences swiftly resolved.

J.L. Stoik, President and chief executive officer.
J.C. Phillips, Chairman of the board.

As 1980 began, it appeared that nothing but opportunity lay ahead for the Canadian petroleum industry.

With significant new oil discoveries in the Arctic and offshore frontiers, and several new oil sands plants on the drawing boards, Canada was one of the few industrialized nations in the world with the potential of achieving self-sufficiency in oil by the end of the decade.

The frontier allowance incentives, instituted in 1977, were instrumental in accelerating the pace of costly exploration in the remote frontier areas and led to major oil and gas discoveries in the Beaufort Sea and off the east coast. Unfortunately, those incentives were permitted to expire at the end of March, 1980.

Increased producer netbacks from sales of crude oil and natural gas had stimulated exploratory drilling in the western provinces to record levels and assured Canada of abundant gas reserves well into the 21st century.

The limited markets available for the new gas discoveries were creating financial problems for some of the smaller exploration companies, but the federal government was pursuing programs to substitute Canada's abundant natural gas for costly imported oil, and there was hope of additional export markets in the short term.

A consensus had formed among economists that energy developments were going to be the "engine" driving the rest of the Canadian economy to greater prosperity throughout the 1980s.

It was estimated that the proportion of the Gross National Product related to energy investment would have to increase sharply from the average levels of the 1970s to approximately six per cent during the 1980s, if complete energy independence was to be reached by the end of the decade.

The capital investment required for Canada to achieve oil self-sufficiency by 1990 was estimated at a staggering $250 billion during the decade. Nevertheless, industry spokesmen, bankers and other financial experts were confident that the necessary funds would be available from domestic and foreign sources—in view of the industry's bright outlook in a relatively stable economic and political environment with great resource potential.

Gulf Canada's reinvestment record has been impressive—averaging 95 per cent of cash flows over the past five years. Annual capital and exploration spending, which had been just below the half-billion dollar mark for several years, surpassed that level in 1980, reaching $572 million.

As one of the most successful companies in frontier exploration, Gulf Canada was gearing up to assume its full share of the increased investment required to move Canada toward oil self-sufficiency by 1990. In our long-range planning process, we had authorized expenditures in excess of $1 billion for 1981. The Corporation's 75th year in business was to have been our first billion-dollar year for capital and exploratory investment.

But all that was before the new National Energy Program (NEP) was announced in conjunction with the October 28, 1980 federal budget.

Now the 1980s are in danger of going down in Canadian history as "the decade that might have been," if the new National Energy Program is not further amended and federal-provincial energy differences swiftly resolved—including the question of offshore jurisdiction.

The primary objective of the NEP was said to be self-sufficiency in oil by 1990. However, it was soon clear to most of the nation that this all-important objective—holding the key to Canada's economic prosperity in the 1980s—had been sacrificed in favor of sharply increased government revenues and a counter-productive program to accelerate Canadianization of the industry.

The most costly aspect of the new federal policies is the eight per cent tax on the net wellhead price of oil and gas production, including provincial royalties. Since this tax is not deductible in calculating income taxes, the effective rate for a company like Gulf Canada will be approximately doubled. This tax has seriously eroded the "resource allowance" which was the measure created in 1974 to lead the way out of the last federal-provincial impasse over petroleum revenue-sharing.

The second most costly feature of the new program is the withdrawal at the end of 1980 of the 33⅓ per cent earned depletion allowance on all development activities and the staged phase-out of the 33⅓ per cent depletion on exploration by the end of 1983, except on Canada Lands where it will be retained.

Attainment of oil self-sufficiency will require a total effort by all industry participants, and foreign as well as domestic capital.

An assessment of the impact of the NEP on our resource subsidiary, Gulf Canada Resources Inc., indicated a reduction in cash flow of 30 per cent over the next five years. As a result, Gulf Canada reduced its 1981 planned resource expenditures by $210 million, and plans to decrease total spending by $900 million over five years.

The Corporation emphasized, however, that these cutbacks were not irrevocable, and could be reinstated to the extent that cash flows are improved by revisions to the NEP and associated budgetary measures.

Gulf Canada is sympathetic to the idea of policies designed to encourage increased investment by Canadians in their petroleum industry. In fact, progress toward increased Canadian ownership and control of industry assets has been quite dramatic in recent years, without any special incentives.

By the end of 1979, according to the federal government's own monitoring survey, 36 per cent of Canadian oil industry assets were under Canadian control. Projecting the recent trend for a few more years indicates that the government's 1990 objective of 50 per cent Canadian ownership of the oil industry could well be reached early in the 1980s.

Since the government's long-term objective already appears to be within easy reach, there seems little justification for the new Canadianization measures introduced as part of the NEP.

The federal back-in rights on Canada Lands, acquisition by Petro-Canada of foreign-owned companies, the immediate requirement for 50 per cent Canadian content before major energy projects can proceed, and exclusion of multinational affiliates from all but the basic 25 per cent frontier exploration incentive grants will reduce the total amount of work that can be undertaken by the industry.

Since attainment of oil self-sufficiency will require a total effort by all industry participants, and foreign as well as domestic investment capital, Canadian ownership targets should be designed to maintain maximum levels of exploration and development activity.

There is little doubt that the federal government requires additional revenues and that some of these must come from oil and gas production. But there is increasing evidence that the NEP, as currently structured, will be more costly to Canadians than it is worth. This is certainly the case when one takes into account the reduced economic activity and lost employment, as well as increased import dependence and spiralling costs for insecure foreign oil supplies.

Compared with the $5 billion Canada spent for imported oil in 1980, it has been estimated that the escalating cost of increased imports will amount to at least $56 billion during the 1981-85 period.

Since all of this money would leave the country and produce no economic benefit, an increasing number of Canadians are asking how the government can justify paying the full world price to foreign suppliers, but not to Canadian producers whose expenditures generate benefits throughout the entire economy.

As energy investment—the key to Canadian prosperity in the 1980s—began to falter with the delay or cancellation of major projects and exploration cutbacks, it became increasingly obvious that a healthy economy and security of future energy supplies must be the prime concerns of a national energy program.

Before the economic impact of the new programs becomes more serious, it is imperative that federal and provincial officials resolve differences that are delaying Canada's future development and prosperity.

Federal-provincial agreement on realistic prices and revenue-sharing would provide additional revenues for both levels of government and—under revised tax and energy policies—provide the Canadian petroleum industry with the cash flows needed to reinstate deferred or cancelled energy projects. With prompt action, the goal of oil self-sufficiency may still be attainable by the early 1990s.

Unless significant changes are made, it will be difficult for Gulf Canada to sustain the level of earnings and reinvestment achieved during 1980.

Despite the difficult and uncertain environment in which the Corporation now finds itself, we intend to continue to be

We intend to be an aggressive competitor in the industry and a major factor in Canada's developing energy future.

an aggressive competitor in the industry, and a major factor in Canada's energy future.

Management is endeavoring to enhance the growth of shareholder equity by improving operating efficiency, identifying and developing profitable new opportunities and by investigating ways to increase the Canadian ownership of major energy projects in which Gulf Canada plans to participate.

At the Annual General Meeting of Shareholders on April 24, 1980, James E. Lee, President of Gulf Oil Corporation, was elected to the Board of Directors. At the same meeting, shareholders approved a motion to split Gulf Canada's shares on a five-for-one basis, effective May 6, 1980. During the year Gulf Canada's shareholders doubled to almost 40,000, of whom approximately 30,000 are registered at Canadian addresses.

L.P. Blaser, President of Gulf Canada Products Company, retired on February 28, 1981, following 42 years' service. R.T. Brown was appointed President of Gulf Canada Products Company, effective March 1, 1981.

Consolidated net earnings in 1980 increased by $92 million to $380 million or $1.67 per share from $288 million or $1.27 per share in 1979. Earnings represented a 15.3 per cent return on employed capital, compared with 13.3 per cent in 1979.

The Corporation's progress to date reflects the significant contributions of our employees and we express sincere thanks for their continuing efforts.

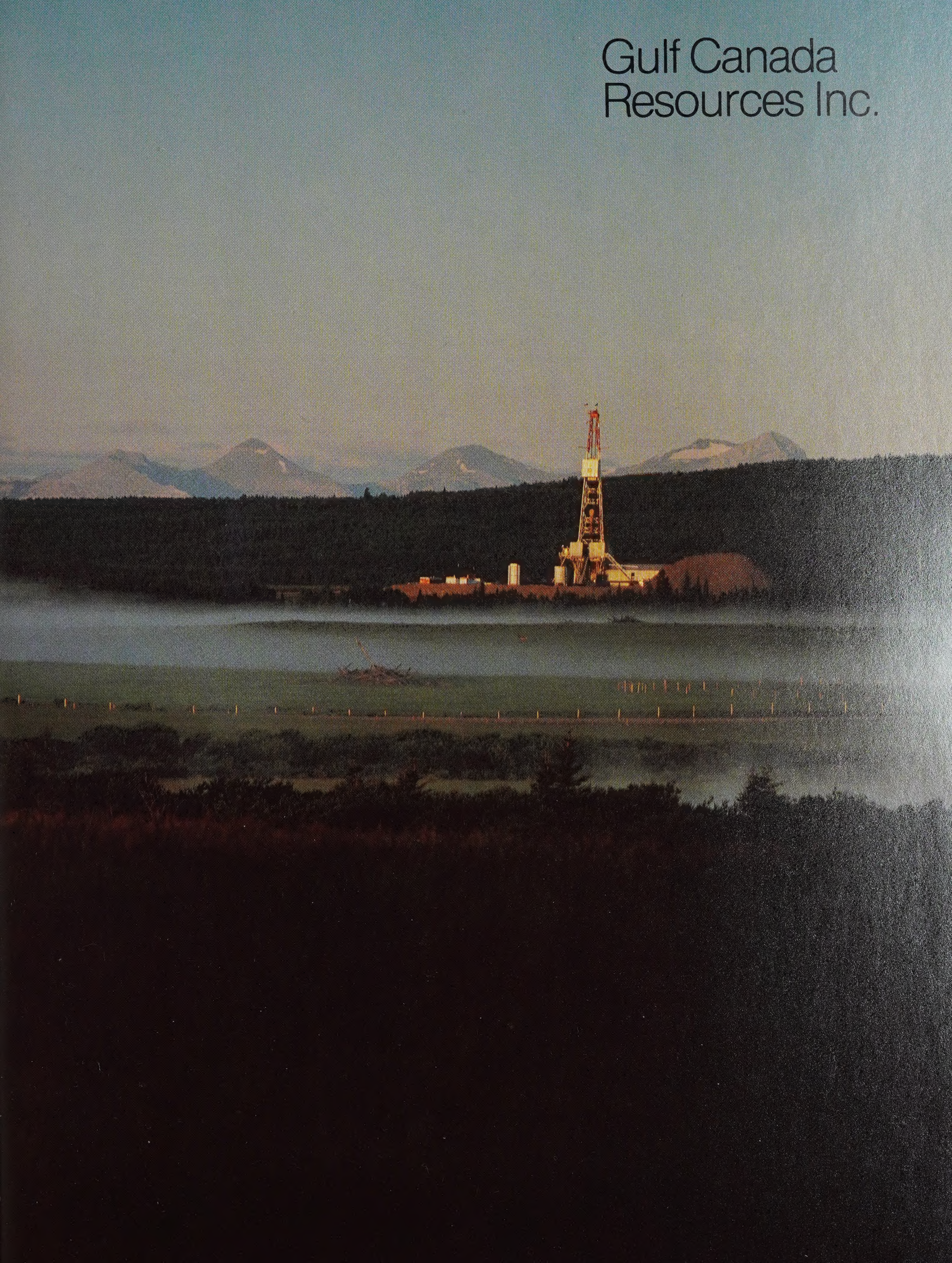
On behalf of the Board,

Chairman of the Board.

President.

Toronto, Ontario, March 20, 1981.

Gulf Canada Resources Inc.



Gulf Canada Resources Inc.

Financial and Operating Summary

Financial	1980	1979
	(millions of dollars)	
Net segment earnings after taxes	**$ 192**	$ 201
Capital and exploratory spending		
Conventional oil and gas	**$ 97**	$ 60
Syncrude	**12**	6
New energy development	**57**	16
Exploration	**287**	209
Minerals	**7**	3
Total	**$ 460**	$ 294
Capital employed at year-end	**$ 889**	$ 751
Return on average capital employed	**23.5%**	26.3%

Operating		
	(thousands of cubic metres per day)	
Gross production		
- Crude oil and natural gas liquids	**20.6**	21.5
- Synthetic crude oil	**1.7**	1.1
- Natural gas produced and sold *(millions)*	**8.9**	11.0

The level of spending of Gulf Canada Resources Inc. (GCRI) increased to $460 million compared to almost $300 million in 1979. Over half the 1980 expenditures were in exploration, up 37 per cent over 1979 due to higher activity levels in Canada's frontier areas. The balance was in conventional oil and gas development as well as outlays for new energy resources in the non-conventional heavy oil areas.

Natural resource earnings of $192 million were $9 million lower than in 1979. An overall revenue improvement due to higher product prices was offset by lower conventional oil and gas volumes and increased operating and exploration expenses. Super depletion allowance on frontier outlays expired on March 31, 1980, and was a significant factor in lower earnings.

Exploration

Exploration expenditures of $287 million in 1980 were a record for Gulf Canada Resources.

Almost half the exploration budget was spent in the frontier areas where successful wildcat and step-out wells have enhanced the importance of the frontiers as major sources of future oil and gas supply.

In western Canada, exploration activities were highlighted by several important gas discoveries in the Alberta foothills and northeastern British Columbia, and encouraging results of drilling on GCRI-interest heavy oil acreage in Saskatchewan.

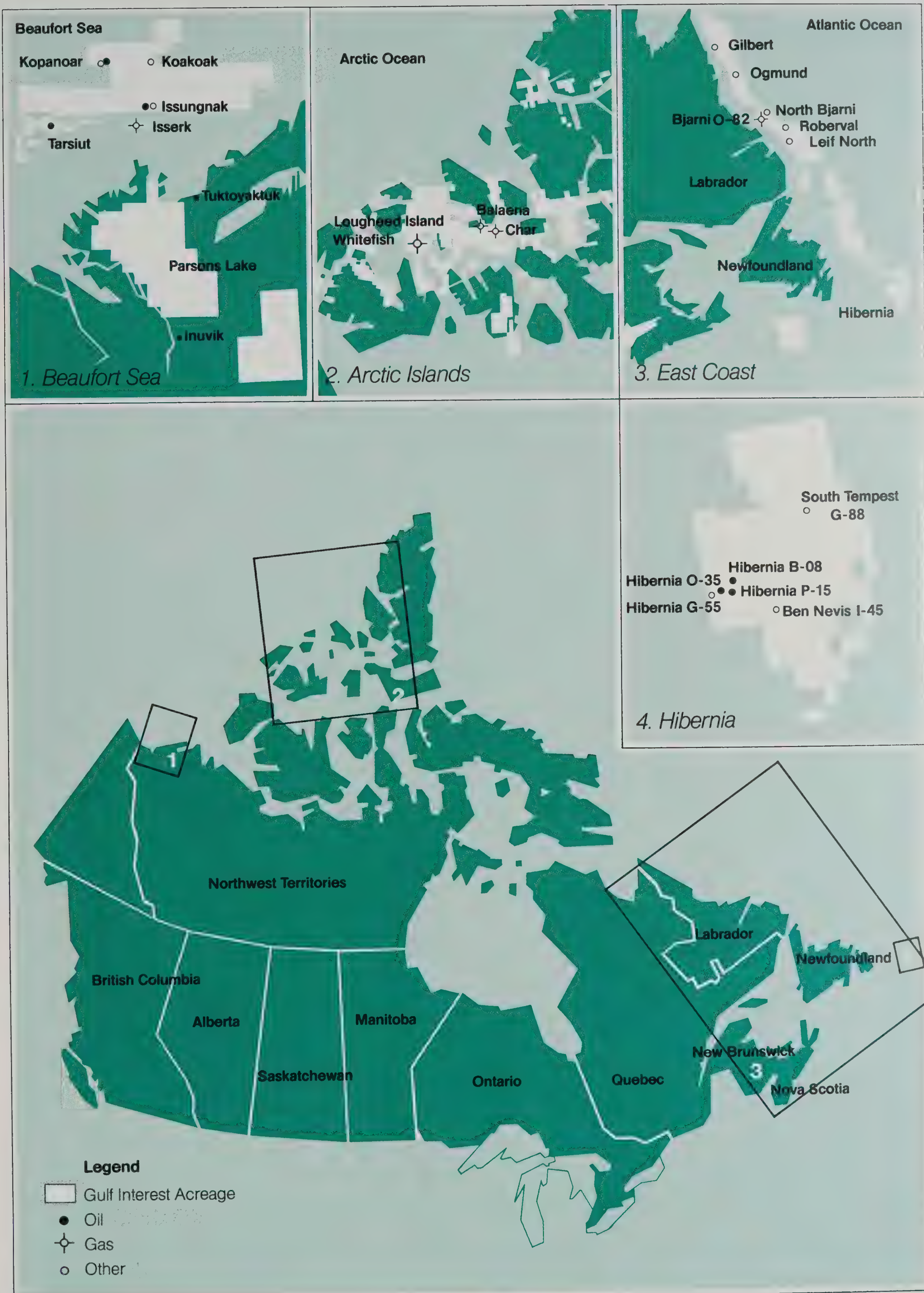
Land Inventory Summary 1980	gross	net
Petroleum and Natural Gas	*(millions of hectares)*	
Western Canada	3.4	1.9
Frontier		
Beaufort Sea	1.0	0.4
Yukon and Northwest Territories	0.8	0.5
Mackenzie Delta	0.5	0.3
Arctic Islands	8.7	1.7
East Coast	20.1	6.0
Frontier Options	0.6	0.2
Total Frontier	31.7	9.1
Oil Sands		
Alberta	0.3	0.2
Total Petroleum/ Natural Gas/Oil Sands	35.4	11.2
Coal		
Western Canada	0.5	0.5
Minerals	0.3	0.1
Total	36.2	11.8

Land

The company believes its interest in over 35 million hectares of land provides excellent representation in all major areas for both conventional light oil and gas, heavy oil, and tar sands.

Preceding page:

GCRI-interest wildcat well is part of broadly-based oil and gas exploration program in Alberta foothills and northeastern British Columbia.


Beaufort Sea
Kopanoar
Koakoak
Issungnak
Isserk
Tarsiut
Tuktoyaktuk
Parsons Lake
Inuvik
1. Beaufort Sea
Arctic Ocean
Lougheed Island
Whitefish
Balaena
Char
2. Arctic Islands
Atlantic Ocean
Gilbert
Ogmund
Bjarni O-82
North Bjarni
Roberval
Leif North
Labrador
Newfoundland
Hibernia
3. East Coast
South Tempest
G-88
Hibernia B-08
Hibernia O-35
Hibernia P-15
Hibernia G-55
Ben Nevis I-45
4. Hibernia
Northwest Territories
British Columbia
Alberta
Saskatchewan
Manitoba
Ontario
Quebec
Labrador
Newfoundland
New Brunswick
Nova Scotia
Legend
Gulf Interest Acreage
Oil
Gas
Other

FRONTIERS

East coast offshore

Following completion of testing of the 3,000-cubic-metres-per-day oil discovery at Hibernia on the Grand Banks in late 1979, GCRI and partners commenced a three-rig program to evaluate the 212,000-hectare Hibernia block, and explore the adjacent 2,362,000 hectares in which GCRI has interests. The first Hibernia step-out well, O-35, drilled four kilometres west of the P-15 discovery, encountered good quality oil in several zones and tested at rates up to 494 cubic metres per day in a single zone. This well established oil in the Avalon sands which were productive in the P-15 discovery. The daily production rate of O-35 is similar to that of the discovery well.

Testing of the Hibernia B-08 step-out, four kilometres north of the Hibernia discovery, was completed at year-end. The well tested oil from several zones within the Hibernia sand at rates up to 911 cubic metres per day. A number of new zones above the Hibernia sand flowed oil and gas at significant rates.

A third Hibernia step-out, G-55, eight kilometres west of the Hibernia P-15 discovery, was plugged and abandoned early in 1981 without encountering hydrocarbons.

On the 2,362,000-hectare block immediately east of Hibernia, the Ben Nevis I-45 wildcat, located on a separate structure to the Hibernia wells, yielded encouraging shows of oil. At year-end another well, South Tempest G-88, was drilling about 80 kilometres northeast of Hibernia P-15.

On the Labrador Shelf, a three-ship drilling program was conducted by the Labrador group operated by Petro-Canada. The Gilbert F-53 wildcat, commenced in 1979, was a dry hole as were Ogmund E-72 and Roberval C-02 drilled in 1980. Testing was attempted at Bjarni O-82, drilled in 1979, but was suspended because of mechanical problems. North Bjarni F-06 and Leif North I-05 were started in 1980 and will be completed at a later date.

1

Beaufort Sea

GCRI participated in drilling operations at four Beaufort Sea locations in 1980 to evaluate previous discoveries and test new structures. The program confirmed two discoveries.

The Issungnak O-61 oil and gas discovery was drilled on a separate structure from an artificial island eight kilometres north of the 1979 Isserk gas discovery. Issungnak tested oil at a calculated rate of 382 cubic metres per day, and gas at rates up to 394,000 cubic metres per day from two separate intervals. In addition to its interest in Issungnak, GCRI has interests in lands off-setting the block on three sides.

An Issungnak step-out was being directionally drilled from the artificial island at year-end and will be completed in 1981.

Approximately 80 kilometres west of Issungnak, the Tarsiut discovery flowed oil at rates up to 127 cubic metres per day.

Two wells could not be completed because of early onset of ice. Koakoak wildcat and Kopanoar I-44, a four-kilometre step-out from the 1979 discovery, will be drilled to their final objectives and tested in 1981.

Arctic islands

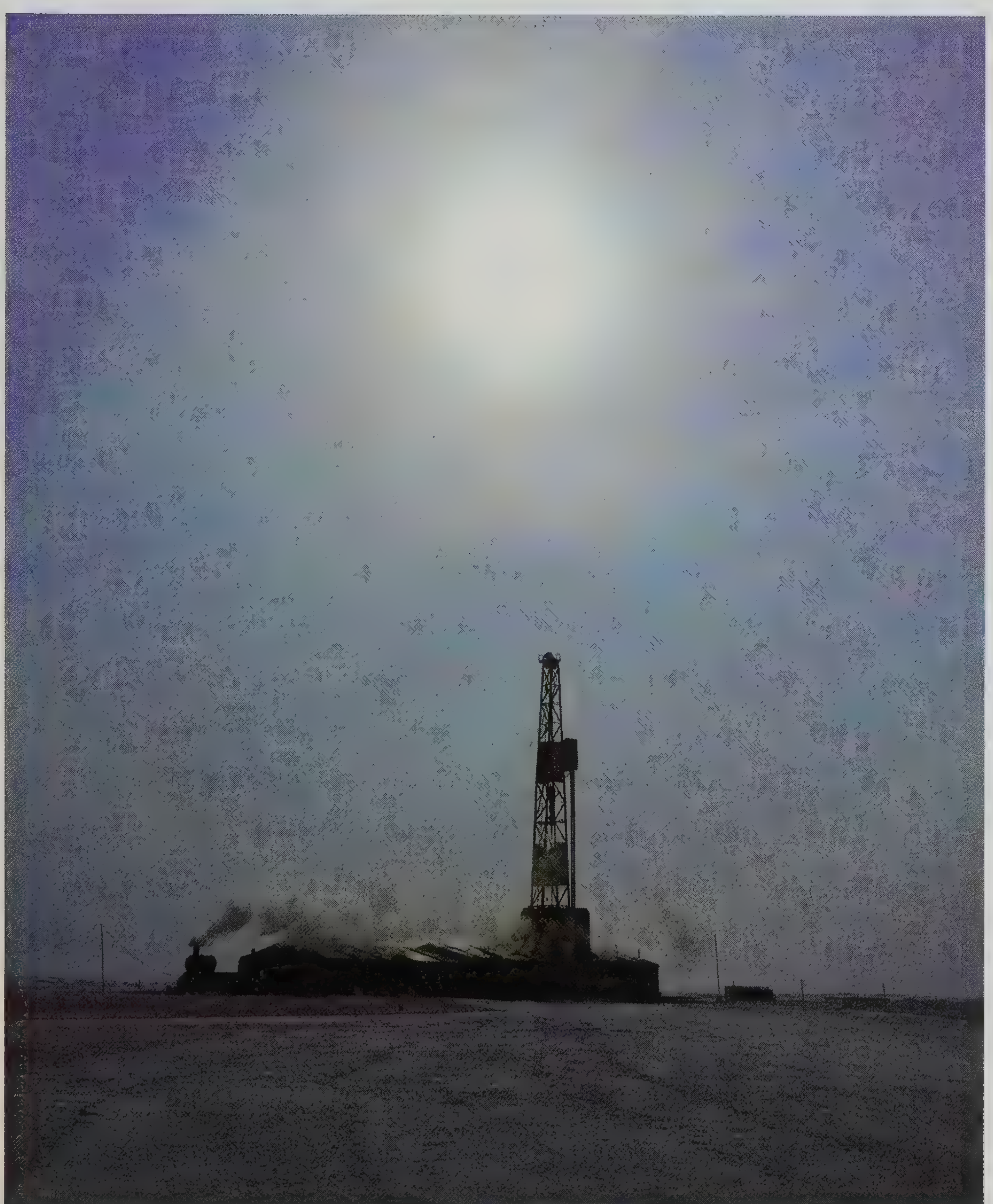
GCRI and partners drilled four Arctic island wells in 1980, the most important of which was Whitefish G-63.

The Whitefish step-out was drilled 245 metres from the original discovery to a deeper depth. The step-out confirmed a major gas discovery with gas flows up 1.25 million cubic metres per day.

Two gas discoveries, Char and Balaena, in which GCRI is earning an interest, were drilled south of King Christian Island and had encouraging oil shows.

In 1981 GCRI plans to drill three wildcats from artificial ice islands in the general Whitefish area around Lougheed Island.

2



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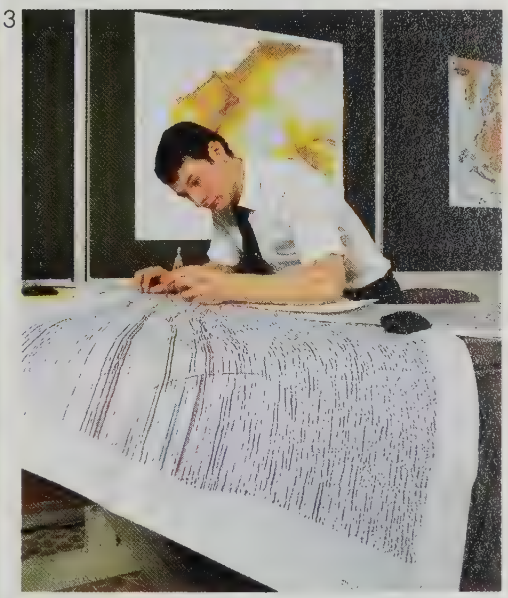


1 Drilled from an artificial island in the Beaufort Sea, the Issungnak 0-61 discovery tested oil and gas from two separate intervals.

2 The Whitefish G-63 well confirmed a major gas discovery in the Arctic islands.

3 GCRI geologist Brian Illing examines a seismic profile of the Grand Banks.

WESTERN CANADA

The company spent $154 million in western Canada exploration in 1980, a $38-million increase over 1979.

A broadly-based exploration program was carried out searching for oil and gas in the Alberta foothills and northeastern British Columbia; conventional heavy oil in Saskatchewan; and light oil prospects throughout Alberta.

Three discovery wells were drilled in the Hanlan-Robb area of the central Alberta foothills, where the company, as operator, plans to build a gas plant. One of these discoveries, Hanlan 3-7, tested gas from a new zone at 930,000 cubic metres per day and is calculated to be capable of producing in excess of 1.4 million cubic metres per day. The company has a strong land position in this area, with a concentration of acreage surrounding the proposed plant.

In northeastern British Columbia, Gulf Canada drilled two discoveries, July and Jackfish, which yielded large gas flows. GCRI's net interest in the discoveries is 100 per cent and 50 per cent respectively.

Exploration in Saskatchewan was concentrated on new and continuing programs to explore and evaluate heavy oil acreage. Gulf Canada is now a major participant in heavy oil exploration and development programs.

The company has an extensive land base in Saskatchewan as a result of participation in the Saskatchewan Heavy Oil Project with Saskoil and Petro-Canada, together with additional farm-ins and new acreage acquisitions of both freehold and Crown Land. During 1980 108 wildcat wells were drilled, 53 of which found oil and three found gas.

Through the Saskatchewan Heavy Oil Project, additional farm-ins and acreage acquisitions, Gulf Canada is now a major participant in heavy oil exploration and development programs.

Tarsiut, one of two Beaufort Sea discoveries in which the company participated in 1980, tested oil at rates up to 127 cubic metres per day.

Production

Crude oil

Gross production of crude oil averaged 17,500 cubic metres per day during 1980, down slightly from 1979 rates because of lower demand and declines in producibility from mature conventional reservoirs. Development of the Edson field in the Alberta foothills in 1980 will result in new oil production in 1981.

At the Willmar field in southeastern Saskatchewan, an enhanced recovery field pilot entered its third phase during the summer with alternate injection of rich gas and water.

In addition, significant changes were approved and partially implemented on an enhanced recovery miscible flood project in Alberta's South Swan Hills field. In most of the project area, the rich gas injection was successful and was followed by lean gas injection. To improve recovery, miscible gas injection will be continued in seven recently-drilled wells. In the field's West Waterflood area, construction began on a tertiary miscible gas project to be started up in 1981.

Two additional company-operated enhanced recovery projects will be under construction in 1981 and, together with the projects already in operation, are expected to increase recoverable reserves.

During the year 116 gross heavy oil wells were drilled which delineated significant reserves of conventional heavy oil in Saskatchewan.

In order to improve recovery over that obtained by primary techniques, pilot thermal steam tests will be carried out on Saskatchewan heavy oil acreage. Initial single-well evaluation steam tests started in late 1980.

During 1980 Gulf Canada concluded a farm-in agreement on 47,000 hectares of heavy oil property in west-central Saskatchewan which will provide the company with a 46.5 per cent interest for an expenditure of $40 million. A major portion of development capital will be spent on enhanced recovery production methods.

Natural gas

Gross production of natural gas was 8.9 million cubic metres per day, down substantially from 1979 due primarily to reduced U.S. demand. Gas liquids production was 3,100 cubic metres per day.

During the year the Stolberg gas field was brought on stream, producing sour gas at the contracted rate of 570,000 cubic metres per day. The field, discovered in 1958, was delineated and developed during the following 20 years at a cost of $30 million. Gulf Canada has a 37.5 per cent interest in the unit.

The Alberta Energy Resources Conservation Board approved plans to build the $250-million, 8.5 million-cubic-metre-per-day Hanlan-Robb natural gas plant near Edson, Alberta. As operator, Gulf Canada will have a 37 per cent interest in the project. The plant is scheduled to go on stream by the end of 1982, processing sour gas from the company's Hanlan-Robb discoveries. Production will be connected to the eastern leg of the Alaska Highway Natural Gas Pipeline prebuild.

Development and outpost drilling resulted in 51 net wells, of which 31 were designated as oil and 20 as gas.

Gross proved reserves of crude oil, natural gas liquids and natural gas continued to decline in 1980. The decrease in proved reserves of conventional crude oil and natural gas liquids, from 58.2 million cubic metres to 55.0 million cubic metres, was approximately the same as in 1979. Proved reserves of natural gas were down from 70.2 billion cubic metres to 69.6 billion cubic metres due to continuing depletion of older reserves.

The Rimbey Gas Plant is one of the major GCRI-operated processing facilities in Alberta.

Estimated Remaining Reserves

	gross	net
	1980/79	**1980**/79
Crude Oil and Natural Gas Liquids	*(millions of cubic metres)*	
Western Canada		
– Proved (1)	**55.0**/58.2	**35.6**/38.6
– Established (2)	**72.0**/75.0	**46.5**/*
Rest of Canada (3)		
– Established (2)	**9.0**/16.0	**7.1**/*
Natural Gas	*(billions of cubic metres)*	
Western Canada		
– Proved (1)	**69.6**/70.2	**50.4**/51.9
– Established (2)	**85.1**/84.1	**61.6**/*
Rest of Canada (3)		
– Established (2)	**45.6**/62.4	**38.8**/*
Synthetic Crude	*(millions of cubic metres)*	
Syncrude (4)		
– Proved (1)	**23.2**/23.8	**16.4**/17.0
Sulphur	*(millions of tonnes)*	
– Proved	**4.5**/4.8	**3.6**/3.9

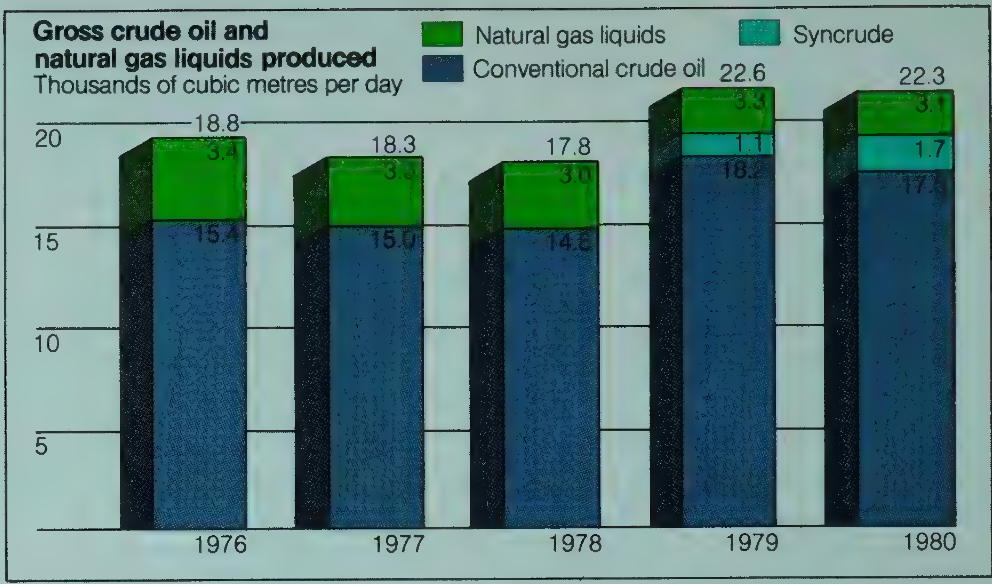
*Not available

(1) Proved gross reserves are before deducting royalties. Net proved reserves are after deducting royalties which vary depending on prices, production rates and legislative changes. Proved reserves are those which appear with reasonable certainty to be recoverable in the future under existing economic and operating conditions.

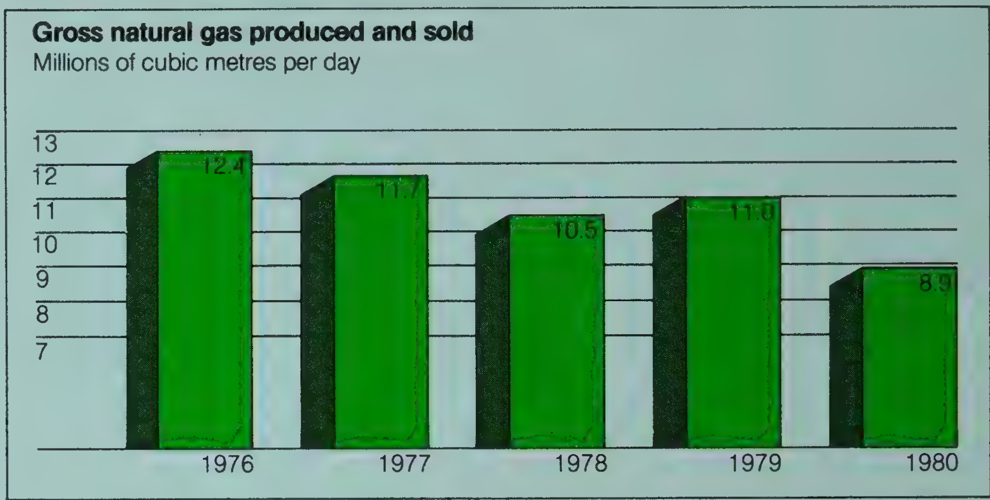
(2) The definition for the established category is the same as recommended by the Canadian Petroleum Association, the National Energy Board and the Alberta Energy Resources Conservation Board. Established reserves are those reserves which appear with reasonable certainty to be recoverable in the future under existing and anticipated economic conditions. Proved reserves are part of this category.

(3) The rest of Canada includes frontier and east coast reserves in areas such as at Parsons Lake, Whitefish, Kopanoar and Hibernia.

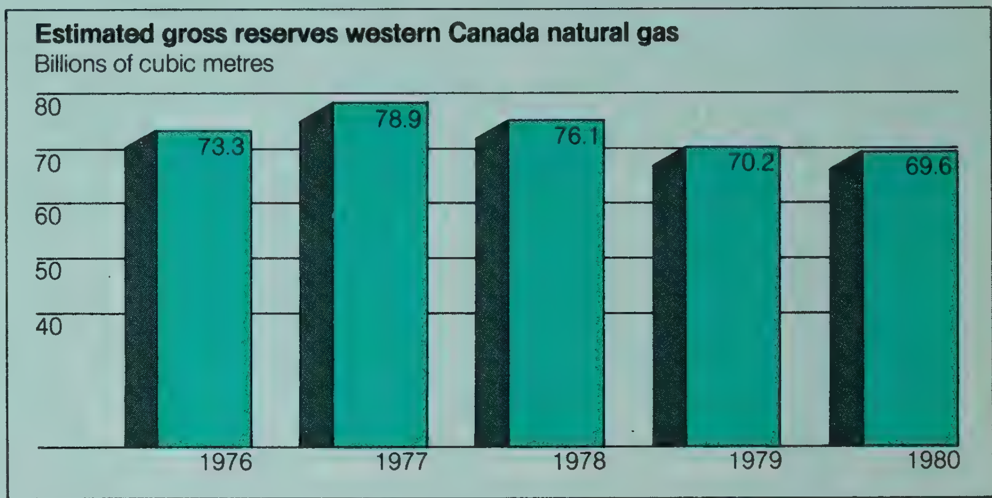
(4) Synthetic crude oil reserves resulting from Gulf Canada's interest in the Syncrude project are shown in gross and net volumes. The Alberta government's share from the Syncrude project is 50 per cent of net profits, as defined in an agreement between the project participants and the government, with an option to convert to a 7.5 per cent gross royalty. On either basis, the Alberta government has the right to take its share in kind. These reserves will be extracted by mining and processing oil sands.



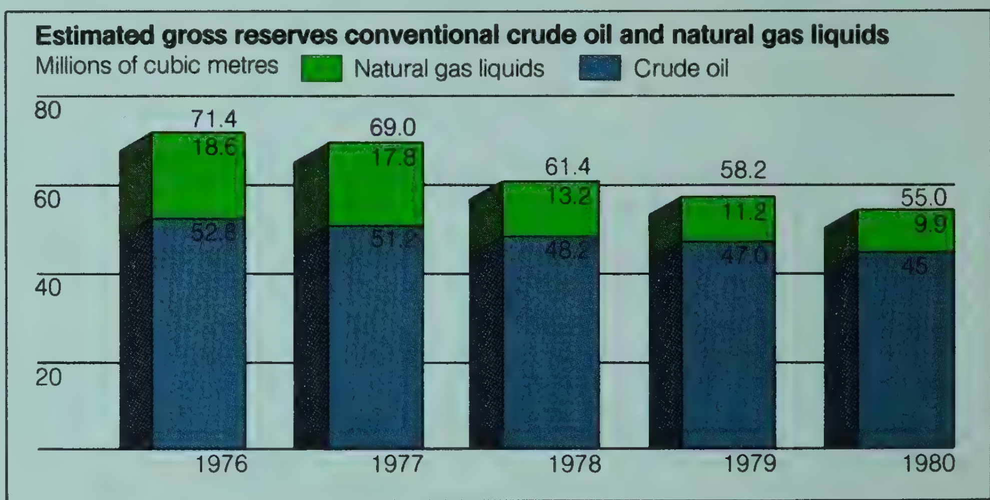
Gross crude oil and natural gas liquids produced
Thousands of cubic metres per day



Gross natural gas produced and sold
Millions of cubic metres per day



Estimated gross reserves western Canada natural gas
Billions of cubic metres



Estimated gross reserves conventional crude oil and natural gas liquids
Millions of cubic metres

1

2

Sulphur

Net sulphur volume declined slightly as a result of lower natural gas production. However, sulphur sales increased from 249,000 tonnes in 1979 to 343,000 tonnes in 1980 and reduced inventory at Strachan Gas Plant.

North America's first sulphur prilling tower at the Strachan plant began operations in the spring and by year-end was prilling 1,000 tonnes of sulphur daily for export.

New Energy Resources

In addition to managing its investment in the Syncrude operation, GCRI's oil sands activity in 1980 was focused on resource evaluation and development of improved technology to provide future energy supplies. In coal, GCRI continued its program of acquisition and evaluation of strategically located deposits.

Additional capital investment in both segments reached $69 million. GCRI's cumulative investment in the development of current and future energy supplies from oil sands and coal is now in excess of $400 million.

1 Production of synthetic crude oil at the Syncrude project, in which Gulf Canada has a 13.4 per cent interest, averaged 12,700 cubic metres per day in 1980.

2 At Strachan Gas Plant, North America's first sulphur prilling tower, was producing 1,000 tonnes of prilled sulphur per day by year-end.

Mineable oil sands

Total production of synthetic crude oil by Syncrude averaged 12,700 cubic metres per day, compared to 7,900 cubic metres per day in 1979. During 1980 Syncrude operated profitably for the first time since start-up and contributed significantly to GCRI's 1980 earnings.

At year-end the Alsands Project Group—in which GCRI holds an eight per cent interest—was assessing the effect that prolonged inter-governmental disagreement will have on the project's start-up, costs and long-term feasibility. Because of unresolved differences between the federal and Alberta governments, the project consortium cancelled the $50-million 1980/81 winter work program, and significantly reduced planned 1981 expenditures. The group continued to develop design details for the proposed 22,000 cubic-metre-per-day facility, selecting a joint-venture management contractor to do detailed design and supervise construction.

In the Sandalta project, GCRI earned a 33 per cent interest in Bituminous Sands Lease No. 30 with the completion of the Phase I, 85-well exploratory drilling program, and the commencement of an additional 100-well evaluation program under Phase II. Future work will enable the company to earn up to an 83.75 per cent interest in the 15,000-hectare lease north of Fort McMurray.

Late in the year the company exercised an option and doubled its interest to 20 per cent in six other Athabasca area leases totalling 75,000 hectares. A work program is planned for 1981.

In situ oil sands

In addition to being active in mineable oil sands, GCRI is a leader in the development of technology to produce bitumen from Alberta's deeper oil sands deposits. The major portion of bitumen in the oil sands can be recovered only by in situ techniques because of its depth. Experimental techniques employ steam, solvents, or fire-flood to reduce the viscosity of the oil so it can be pumped to the surface. The company previously conducted experimental in situ pilot projects at Wabasca and Cold Lake, and currently has interests in three other similar projects.

On the Wabasca in situ acreage, construction began on a new pilot plant at nearby Pelican Lake which will use fire and steam techniques to test a deeper oil formation. Designed to initially produce 480 cubic metres of bitumen per day, the pilot will be operational by mid-1981.

A drilling program on GCRI's 48,160 hectares in the Surmont area of the Athabasca deposit has confirmed the presence of high quality bitumen deposits and steam stimulation field tests have provided encouraging results. Two pilot projects are underway on the lease: Surmont, to develop a new recovery technique; Resdeln, to evaluate production.

The Surmont project, a joint GCRI and Alberta Oil Sands Technology and Research Authority development, will test the value of horizontal wells drilled directly from the surface and underground wells drilled from tunnels constructed within or immediately above or below the oil sands formation. Site selection and engineering feasibility studies will be completed in 1981.

The nearby Resdeln project will evaluate reservoir producibility using steam stimulation from surface-drilled vertical wells. Facility construction at Resdeln was completed in 1980, and production is projected to average 64 cubic metres per day during the planned two-year operational period.

Opposite page:

At Resdeln, 32 kilometres southeast of Fort McMurray, steam stimulation from surface-drilled vertical wells will be used to evaluate reservoir production from in situ sands.

A new pilot project at Pelican Lake on the company's Wabasca in situ oil sands acreage will go into operation in mid-1981.

Coal

Since its first major coal exploration venture in 1978, the company has substantially stepped up its search for this resource. By year-end GCRI had increased its land holdings to approximately 470,000 net hectares of coal rights in western Canada. The Goodrich property in northeastern British Columbia was the principal area of land acquisition, and drilling has started to evaluate its mining potential.

GCRI's most advanced project is at Belcourt in northeastern British Columbia where Gulf Canada is a 40 per cent partner with Denison Mines Limited. A preliminary study indicated a potential yield of about 80 million tonnes of clean bituminous coal from surface mines.

Two other projects in British Columbia—at Trefi and Wapiti—were drilled. Preliminary results at Trefi, 30 kilometres west of Chetwynd, indicated a bituminous coal of medium volatility with underground mining potential. Exploration programs outlined substantial near-surface resources at the Wapiti project, 35 kilometres southwest of Dawson Creek.

The Chip Lake sub-bituminous coal project, 40 kilometres west of Alberta's Lake Wabamun coal mining district, has potential for underground mining.

GCRI research in 1980 included a small scale in situ coal burn test at the Wapiti site. An assessment is also underway to determine the application of coal conversion technologies to coal resources.

Environmental planning

As a part of the company's business planning, the production and new energy resources environmental groups provide input to operating activities to ensure the protection of the natural and human environment. Environmental assessments during 1980 were directed in particular to the Hanlan-Robb gas plant and gathering system, the Sandalta project, the Goodrich property and Saskatchewan heavy oil developments.

Minerals

Gulf Canada Limited has a 5.1 per cent interest in the Rabbit Lake uranium mine in Saskatchewan and a ten per cent interest in adjacent properties. Under a 50 per cent joint venture agreement with Gulf Minerals Canada Limited, the Corporation participates in exploring for uranium and other minerals in other parts of Canada.

Geological assistant Andrea Petzold logs coal core on Goodrich property in northeastern British Columbia.

Gulf Canada Products Company

Gulf Canada Products Company

Financial and Operating Summary

Financial	**1980**	1979
	(millions of dollars)	
Net segment earnings after taxes	**$ 179**	$ 72
Capital expenditures	**$ 94**	$ 47
Capital employed at year-end	**$1,463**	$1,331
Return on average capital employed	**12.8%**	5.6%
Operating		
Crude oil	*(thousands of cubic metres per day)*	
– Processed during year	**46.1**	50.6
– Capacity at year-end	**48.5**	61.4
– Capacity utilized	**88%**	82%
Sales		
Refined products	**42.7**	42.9
	(millions of kilograms per day)	
Chemicals	**1.3**	1.4

Gulf Canada Products Company, (GCPC), formed on July 1, 1979, by consolidating Gulf Canada Limited's refining, marketing, chemicals, supply/distribution and propane operations, has introduced a co-ordinated, integrated approach to the downstream business. The company has plans to spend in excess of $300 million on projects that will expand and modernize its refining capability. In addition, projects and programs were underway or planned to streamline product distribution facilities and improve the appearance of Gulf Canada service stations.

Marketing

Despite continued emphasis on conservation, Canadian industry demand for motor and diesel fuels was slightly higher in 1980. Demand for heating fuels, however, declined sharply because of conservation and conversion of homes and industry to natural gas and electricity.

Product prices rose during 1980 and profit margins improved following the tight product supply situation which developed in late 1979 and continued through 1980.

The company embarked on a national image conversion program which will see

Opposite page:

A nation-wide service station image conversion program featuring new orange/beige color scheme is scheduled for completion in 1982.

Preceding page:

In addition to planned $83-million expansion of reforming and petrochemical facilities at Montreal East Refinery, Gulf Canada is a leading participant in a consortium proposing a projected $1.8-billion heavy oil upgrader for the area.

Right:

Industrial sales represent an important segment of the company's business.


Gulf
27.4
Self Serve

most retail outlets upgraded to an orange/beige combination by 1982.

During 1980 the operations of over 250 low-volume service stations and a number of bulk plants were consolidated in fewer high-volume facilities in strategic locations to provide efficient and convenient service to the motorist at lower operating cost.

HydroTreated lubricants produced at Clarkson Refinery continued to receive wide customer acceptance. Introduced in 1979, these products are now generally recognized as having superior qualities for automotive and industrial lubrication.

Manufacturing

Plans were announced to increase capacity at Edmonton Refinery by 50 per cent, and to enhance its ability to process the synthetic crude oils which will represent an increasing share of future available feedstocks. Cost of the expansion is estimated at $200 million.

At year-end Gulf Canada was a leading participant in a consortium of industry members, together with representatives of the federal and Quebec governments, to evaluate construction of a $1.8-billion heavy fuel oil upgrader in the Montreal area. The project would permit the industry to meet the demand for gasoline and distillates in the most cost-effective manner by significantly reducing production of heavy bunker fuels and crude oil imports.

Also announced was an $83-million program to expand the reforming and petrochemical capability at Montreal East Refinery. At Clarkson, a $40-million program was underway to improve the reliability and capacity of the new lube plant.

Late in 1980 refining operations at Point Tupper Refinery were suspended indefinitely because its process configuration and yields were no longer suitable for refining imported crudes which were becoming more costly and lower in quality. However, the company continues to operate the ocean terminal and products distribution facilities there. Policies were initiated to minimize the impact of the closure on employees and the community and studies are underway to determine the suitability of the location for future projects related to the petroleum industry.

Excluding Point Tupper, refining utilization in 1980 was almost 90 per cent. Western Canada plants operated at capacity to meet continuing high demands, while eastern Canada throughput was moderately restricted by limitations on crude supply.

In its continuing conservation program, the company's manufacturing facilities reduced energy needs by five per cent below 1979 levels—a saving of 53,700 cubic metres of equivalent fuel. Several important energy conservation projects were completed, and more are planned.

Gulf Canada plans to spend $300 million on modernizing and expanding refining facilities. At Edmonton Refinery, a $200-million program will enhance ability to process synthetic crude oils.

Supply and distribution

OPEC official crude oil prices continued to rise early in 1980 in response to unsettled conditions in Iran. By the second quarter, reduced crude demand and continued high OPEC production levels resulted in a surplus position which significantly reduced the spread between official and spot prices. This environment continued until September when loss of supply resulting from the Iraq/Iran conflict caused spot market prices to move higher.

Canadian crude oil prices rose $3.00 per barrel during 1980.

A processing arrangement was made with an east-coast refiner to replace the loss of production as a result of the suspension of refinery operations at Point Tupper.

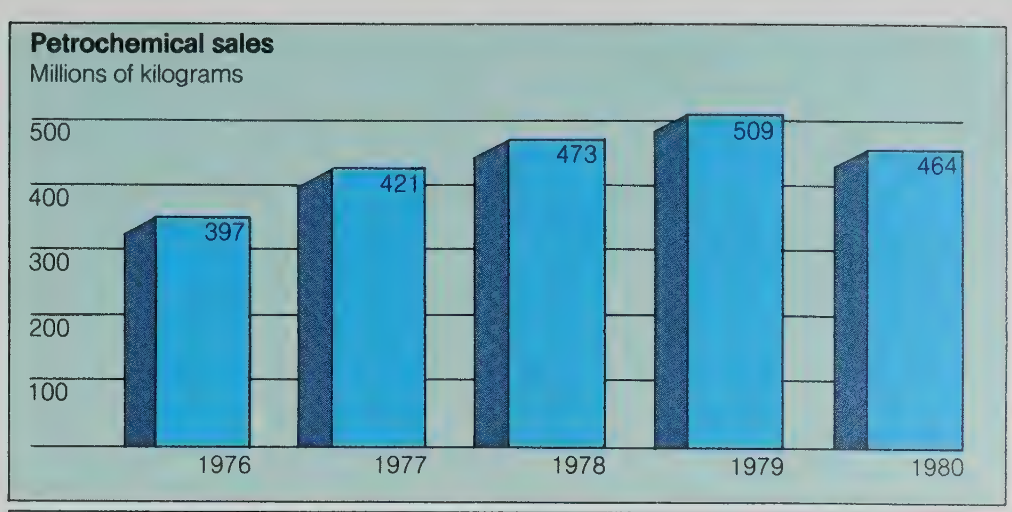
As part of Gulf Canada's program to diversify foreign crude supplies, direct purchase contracts were signed with Iraq and Venezuela in early 1980. On December 31, 1980, Gulf Canada received formal notice from Iraq that the crude oil contract was being cancelled due to hostilities with Iran. However, available crude supplies were adequate to meet existing product requirements.

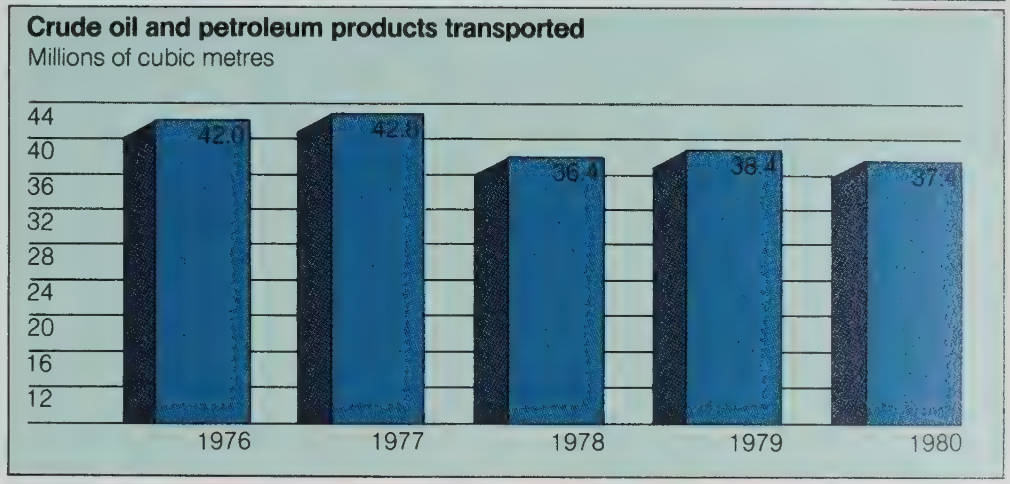
As part of Gulf Canada's ongoing program to improve distribution efficiency, a fully-automated loading facility adjacent to Montreal East Refinery will be completed in 1982.

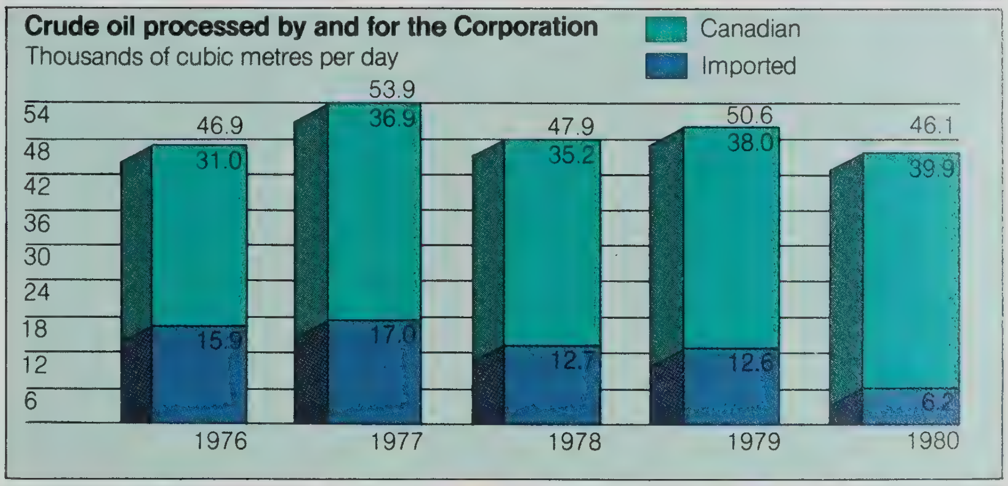
Chemicals

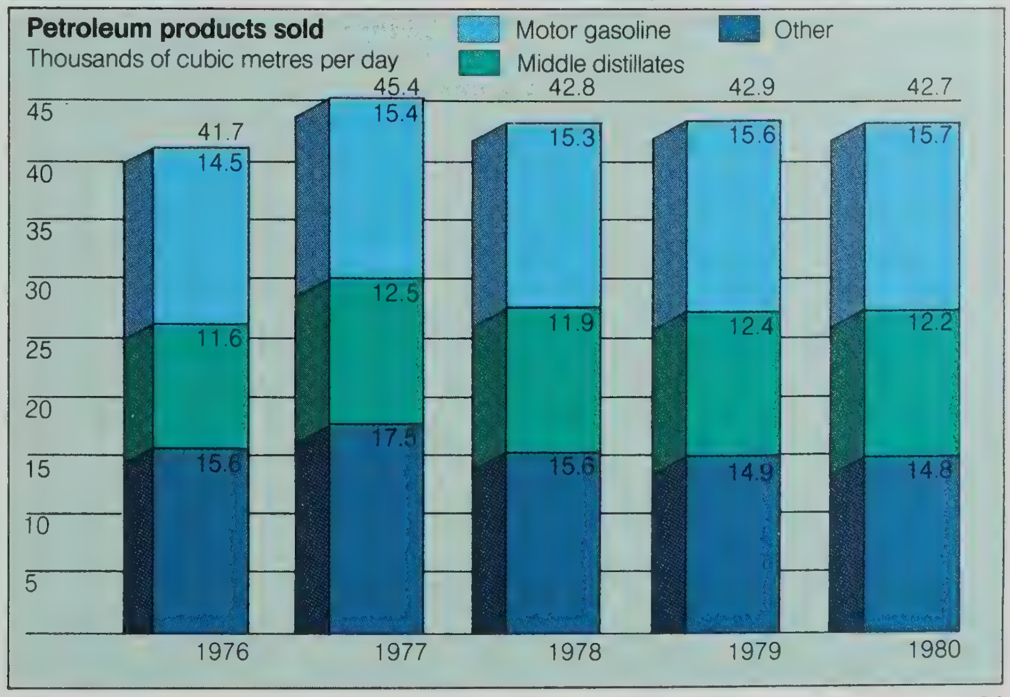
The aromatic facilities in Montreal East which produce benzene, cumene, phenol and cyclohexane operated at near capacity. Demand for phenol was beyond plant capacity, and some phenol was imported to protect the company's market share.

The inorganic chemicals plants at Shawinigan and Bedford operated at 70 per cent capacity, mainly because of start-up problems associated with a new calcium carbide furnace at Shawinigan. During the year, work began on installation of facilities at Shawinigan for production of a calcium carbide desulphurizing reagent for the steel industry.









On October 1, 1980, the company's 225-million-kilograms-per-year ethylene producing facility at Varennes became part of the new Petromont venture. This Montreal-based petrochemical consortium consists of Gulf Canada Limited, Union Carbide Canada Limited and Société générale de financement du Québec. Gulf Canada Products Company is operating the Varennes plant on behalf of Petromont.

Commercial Alcohols, a wholly-owned Montreal-based subsidiary with a synthetic ethanol plant at Varennes, operated at capacity with 60 per cent of the production being exported.

The former Varennes plant is now the cornerstone of the Petromont petrochemical consortium headed by John Dinsmore.

The *ST Gulf Canada,* delivering a cargo to St. John's, Newfoundland, terminal, is one of three company-owned-and-operated tankers moving crude oil and finished products between refineries and terminals in the Atlantic provinces and as far west as the lakehead.

Other Activities

Research and development

Research and development activities continue to focus on projects directly related to securing Canada's energy future. The Sheridan Park centre has developed significant capability for investigating and developing new technology relating to recovery and upgrading of heavy oil.

In 1980 field and laboratory studies were conducted in conjunction with production field pilot-plant experiments in enhanced recovery, heavy oil and in situ oil sands. A major activity was evaluation of a large number of processes to upgrade heavy oil and tar sands into acceptable refinery feedstocks and subsequently into marketable products.

The Corporation participated in the development of the fluid to be used in GCRI's West Willmar enhanced recovery project and is undertaking similar studies for future enhanced recovery programs.

Evaluation of uses for GCRI's coal reserves is continuing. With technology advances and government subsidies, coal could be converted to gases and liquids to provide energy for the future.

With conservation playing an increasingly important role, the Corporation has developed special conservation capabilities. For example, a custom-designed mobile combustion efficiency laboratory is conducting studies at plants across Canada.

Gulf Canada's role in energy development continues to receive priority attention. Consistent with business strategies, plans call for increased emphasis on technologies for development of new energy resources.

Environmental affairs

Capital expenditures of $22.6 million directed toward environmental conservation were associated with drilling operations, new capital projects and environmental upgrading of existing facilities.

Work continued in both upstream and downstream companies, including study for the proposed Hanlan-Robb gas plant and an environmental assessment of the Edmonton Refinery expansion.

Gulf Canada's program of systematic upgrading and replacing older underground product storage tanks will require an estimated expenditure of $17 million over the next decade. A new $4-million open-pond biological treatment facility at Montreal will further improve the quality of effluents from the refinery and phenol plant.

The Corporation continues to play a leading role in setting forth the industry's position on government environmental regulation to ensure that cost-benefit considerations remain prominent in the regulatory process.

Realty

The first full year of occupancy of Gulf Canada Square in Calgary has demonstrated an energy-efficiency capability even better than predicted. Total energy consumed for office heating, cooling, lighting and general office equipment has been less than half the 20 to 25 kilowatt hours per square foot per annum required for most modern office buildings—well below the 53 kilowatt hours estimated as the average of large buildings built in the last 15 years.

Gulf Canada occupies approximately 60 per cent of the office space with the balance being fully leased. Retail space is approximately 85 per cent occupied.

Preceding page:

Among GCRI personnel involved in management training studies are John Loh (l), Kasper Lund and Bev Loney. Anticipating a continuing shortage of skilled technical and professional employees, Gulf Canada has developed a strong capability in recruitment and training.

At the Corporation's Research Centre near Toronto, technology scientist Denis Guimond uses a high-pressure simulator to find new ways of recovering heavy oil.

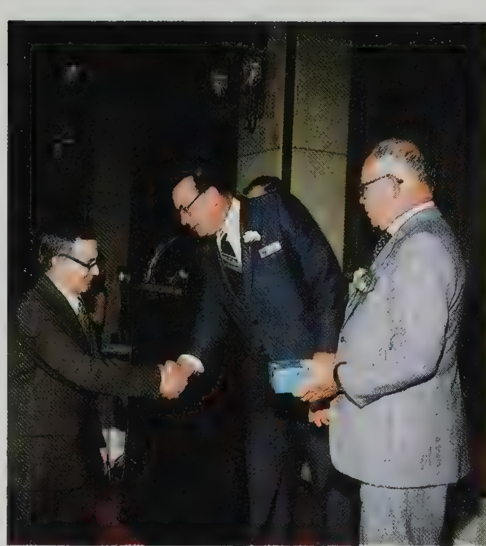
Human resources

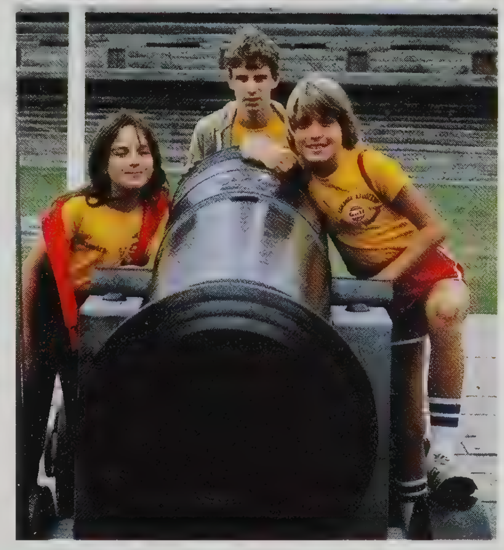
A serious shortage of personnel in the skilled, technical and professional disciplines is expected to continue over the next several years. To overcome this potential difficulty in staffing new projects, Gulf Canada has established a comprehensive recruiting and training capability.

During 1980, 207 employees with 25 years of service were honored at dinners hosted by the Corporation's officers at Calgary, Montreal and Toronto. The number of employees with service credit in excess of 25 years now totals 1,632.

Pre-retirement counselling sessions for employees approaching retirement were well received.

Labor contracts for 1980 were negotiated on the basis of a 10.5 per cent wage settlement. With the merger of the Oil, Chemical and Atomic Workers (OCAW) and the Canadian Chemical Workers (CCW), the resultant Energy and Chemical Workers Union (ECWU) is now the bargaining agent at locations formerly having OCAW representation. The good relationship that existed between Gulf Canada and the OCAW is expected to continue with the new union.





Public affairs

During the year Gulf Canada continued to demonstrate a high level of social responsibility with a somewhat higher profile than in previous years.

A more pro-active process of monitoring and responding to indicated public policy actions was developed and integrated with the Corporation's long-range planning process.

As Gulf Canada continued to prosper, contributions to worthy causes were increased to a record $2.6 million for the support of community activities and public services including health, welfare, educational, cultural and youth projects.

President J.L. Stoik and Chairman J.C. Phillips (r) greeted over 200 employees, including Leopold Rivard from Shawinigan, Quebec, at 25-year service dinners.

Cassandra Cross (l), Dominic Fournier, Jennifer Dykxhorn were among 70 English- and French-speaking students taking part in Corporation's third annual cultural exchange

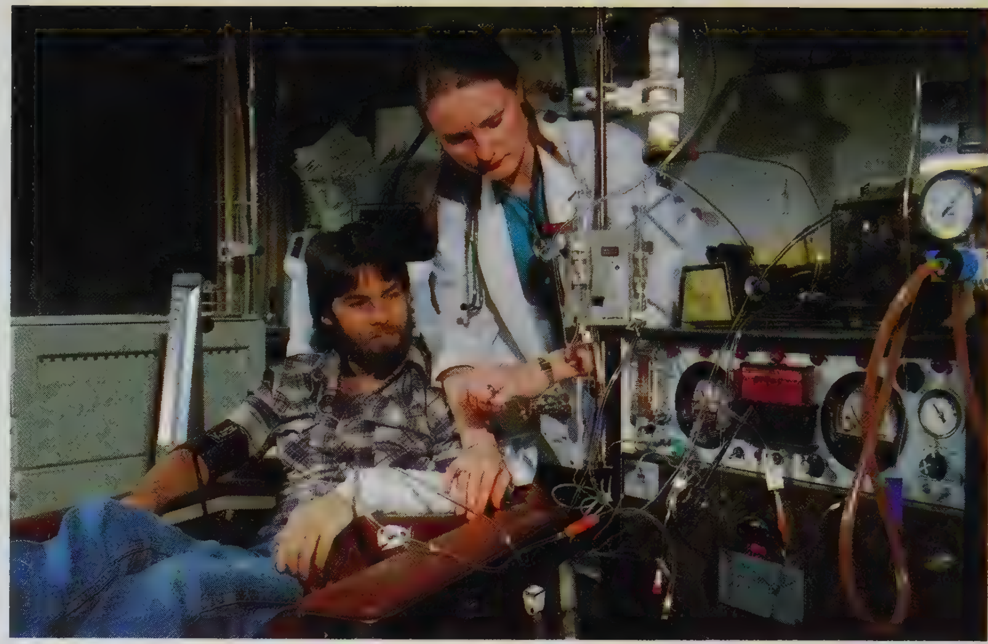
Continued support was given to the National Youth Orchestra which brings together talented young Canadians for a summer of music instruction.

As a project for the International Year of the Disabled in 1981, a special donation of $128,000 was made to purchase 16 cars for the Multiple Sclerosis Society of Canada for transporting MS victims to and from treatment centres. In further aid of the disabled, a major pledge was made to the Canadian Paraplegic Association.

Scores of contributions to the arts in Canada included sponsorship of the highly-regarded production of King Lear at the Stratford Festival. Gulf Canada also underwrote a tour of the Canadian Opera Company and a special performance by the Canadian Brass.

The Corporation adopted a policy in 1980 to facilitate employee involvement in the political process. Employees are also encouraged to contribute to the activities of many worthy national organizations.

A total of 82 university students benefitted from Gulf Canada's fellowship/scholarship/bursary program in 1980. Nine post-graduate students received $7,500 fellowships, of which three were renewals. Under the undergraduate program for dependants of Gulf Canada employees, 15 students were receiving four-year scholarships of $1,500 annually, and 20 were awarded one-time bursaries of $500.



Unclaimed gasoline taxes were used to install 14 kidney dialysis machines in selected Canadian hospitals.

A Stratford Festival production of Shakespeare's King Lear, with Peter Ustinov in the title role, was sponsored by Gulf Canada.

The Canadian National Institute for the Blind is using Gulf Canada donation to provide tape cassettes of current Canadian magazines to the visually impaired.

Gulf Canada: 75 Years of Progress

On October 17, 1981, Gulf Canada will celebrate its 75th anniversary—a significant milestone in its corporate history.

Founder Albert L. Ellsworth, a 32-year-old Welland, Ontario businessman, had a faith in the future of the petroleum industry that was exceeded only by his faith in Canada. And the intervening 75 years have proven him right on both counts.

Canada has grown—and changed; and so has Albert Ellsworth's company.

British American Oil—the name chosen to signify British product quality from American, new-world technology—played a key role in Canada's development through two world wars and the period of unparalleled growth and prosperity that followed World War II.

In 1956, B-A acquired the assets of Canadian Gulf Oil Company, a Calgary-based exploration and production operation, from Gulf Oil Corporation in exchange for common shares. This acquisition put B-A in the forefront of exploration and production activity in western Canada.

In 1966, B-A sold its wholly-owned U.S. producing subsidiary, The British American Oil Producing Company, to concentrate its exploration and production efforts in Canada.

The most visible change came in 1969 when three respected Canadian companies—British American Oil, Royalite Oil and Shawinigan Chemicals—amalgamated to form Gulf Canada.

Royalite's roots went back to the original Dingman #1 well near Calgary, one of the first in Alberta; Royalite was also a pioneer in the Athabasca oil sands development work.

Quebec-based Shawinigan Chemicals was formed in 1898 to produce organic chemicals from limestone. It was later restructured to supply the same products from petroleum when that resource became more readily available.

Throughout its 75-year history, Gulf Canada has been a respected Canadian corporate citizen. At present, 13 of its 14-member Board of Directors are Canadians as are 24 of the 25 Gulf Canada officers.

A substantial research program is carried out at its Sheridan Park Research Centre, near Toronto, and Gulf Canada maintains exclusive world-wide patent rights for its inventions.

Today, Gulf Canada is an aggressive energy corporation with the two-fold challenge of meeting Canada's present energy demands and finding and developing secure energy resources for future generations.

Wooden barrels and milk cans were used to carry kerosene in the early days at the London, Ontario, branch.


REFINERY OF
THE BRITISH AMERICAN OIL CO LIMITED
TORONTO
1


BRITISH AMERICAN OIL CO. Limited
GARAGE
2


BRIT SH AMERICAN OIL CO.
TORON O.
3


4

1. The Corporation's first refinery was built in 1908 on Toronto's eastern waterfront.

2. Trucks replaced horse-drawn wagons at Outremont, Quebec, warehouse in the early 1920s.

3. President Albert Ellsworth and employees marked arrival of B-A's first railway tank car.

4. Clear vision gasoline pumps were a feature of this early-day Toronto service station.

5. On Christmas day, 1935, B-A's wholly-owned U.S. producing subsidiary found a major field on Oklahoma state capitol land.

6. With acquisition of Canadian Gulf Oil Company in 1956, B-A became one of Canada's major fully-integrated oil companies.

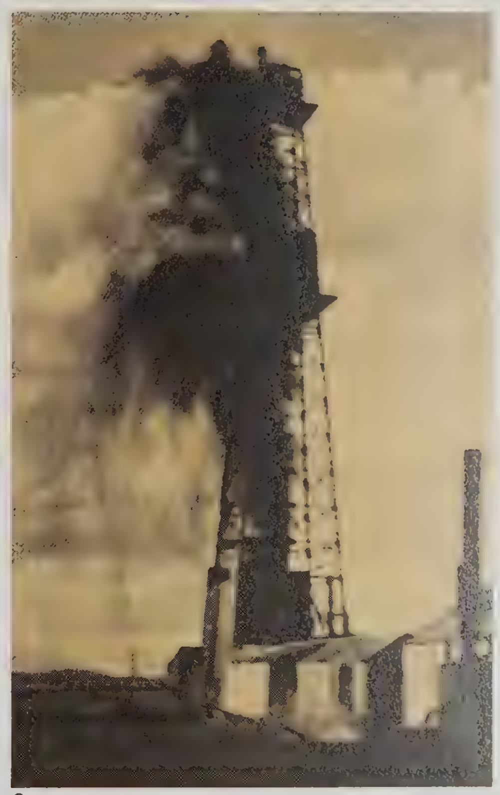
7. Refineries manager L.E. Woolley lit first crude furnace to open Ontario's Clarkson Refinery in 1943.

8. B-A financed discovery of important Turner Valley, Alberta, oil field in 1936.

9. The lake tanker *B A Peerless,* now the *Gulf Canada,* was launched at Collingwood, Ontario, in 1952.

7

5



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10. Employees joined President M.S. Beringer (r) to celebrate Corporation's 50th anniversary in 1956.

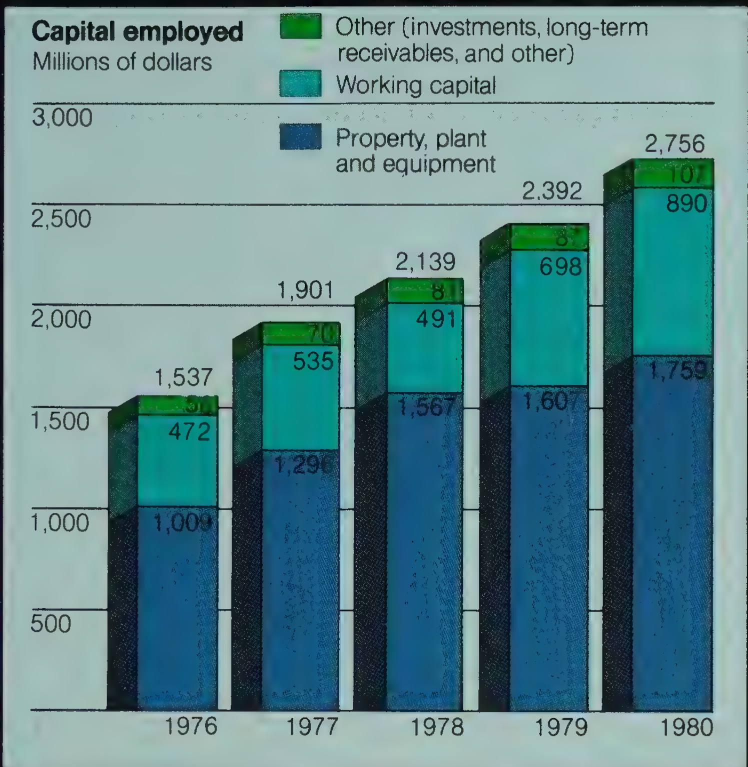
11. Alberta Premier E.C. Manning and Corporation President E.D. Brockett opened expanded Pincher Creek Gas Plant in 1958.

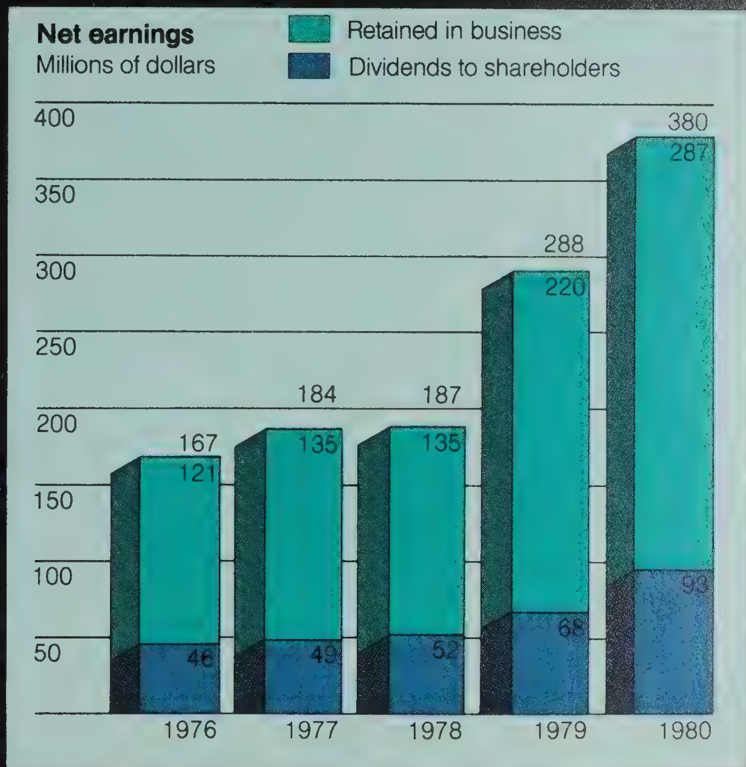
12. In 1964, Ontario Prime Minister John Robarts and B-A President E.D. Loughney opened Corporation's Research Centre near Toronto.

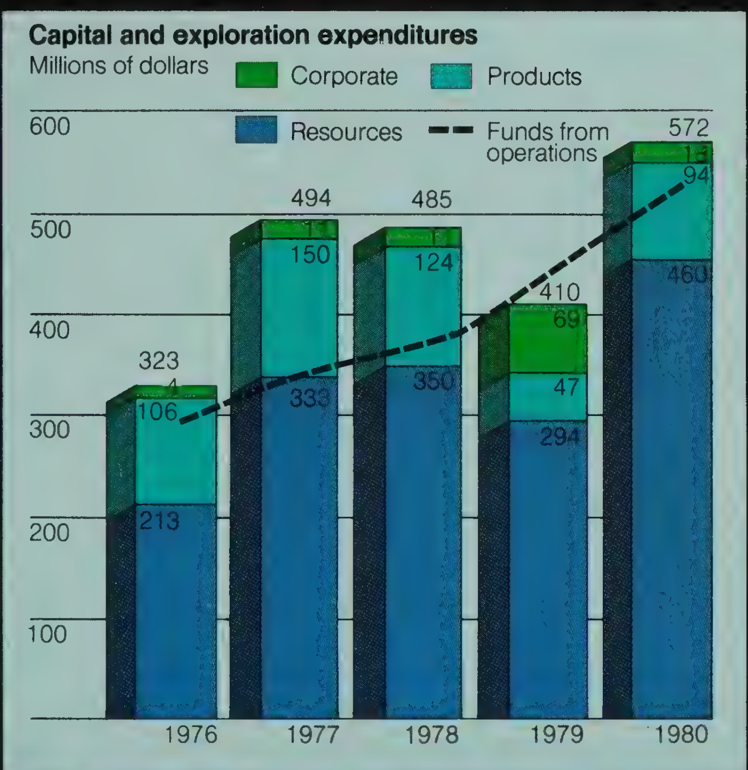
13. Royalite Oil, one of two companies amalgamating with British American in 1969 to form Gulf Canada, pioneered Athabasca oil sands work in the mid-1940s.

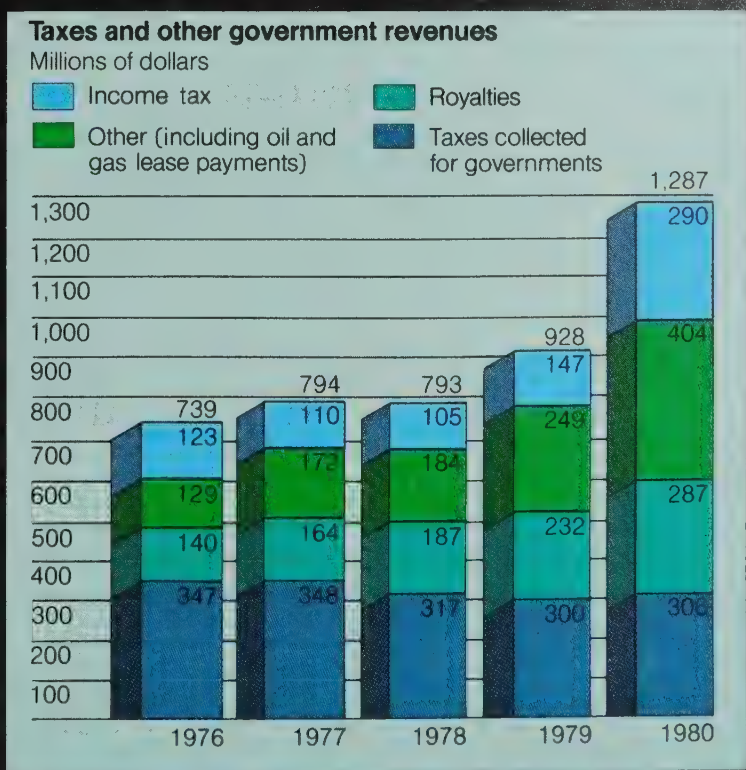
14. Shawinigan Chemicals, the other major partner forming Gulf Canada, had a history in inorganic and organic chemicals dating back to 1898.

Financial Review









Financial Review

Earnings

Earnings for the year were $380 million or $1.67 per share, compared to $288 million or $1.27 per share in 1979.

The 1980 earnings represent a 15.3 per cent return on average capital employed compared to 13.3 per cent in 1979.

Earnings from the natural resource segment fell slightly due primarily to higher exploration and dry hole expenditures which reflected the increased drilling activity this year, mainly in the frontier areas. Net production volumes of crude oil and natural gas liquids, including synthetic crude, declined three per cent to 15,358 cubic metres per day. Net natural gas volumes were down 19 per cent to 6,315 cubic metres per day mainly due to reduced Canadian and export sales. The lower production volumes together with cost increases more than offset improved earnings from the Syncrude project.

The major contribution to the higher earnings came from the refined products and chemical segments. Increased realizations due to firmer market conditions more than offset the impact of lower volumes. Petroleum products sold declined slightly to 42,701 cubic metres per day and chemical sales decreased eleven per cent to 1,246 tonnes per day.

Taxes other than taxes on income rose 72 per cent to $326 million, reflecting mainly the increases during 1980 in the Petroleum Compensation Charge which superseded the Syncrude levy. Income taxes almost doubled to $290 million as a result of higher taxable earnings, the five per cent federal surtax effective from January 1, 1980, and the expiration, on March 31, 1980, of the frontier exploration allowance. A summary of taxes and other government revenues are shown in a bar chart on page 33.

Overall revenue and cost trends are discussed in detail in the "Management discussion and analysis of financial conditions and results of operations," beginning on page 48.

Financial position

Funds from operations before exploration expenditures increased $212 million to $788 million, due mainly to higher earnings before non-cash items. Sales of properties and investments, together with deferred gas production revenue, were other sources of funds for the Corporation and totalled $91 million.

Capital and exploration spending increased 40 per cent or $162 million to $572 million. The major portion of these expenditures was incurred for land acquisitions and other projects related to the exploration and production of natural resources.

Dividends of $93 million and repayments of long-term debt of $18 million represented the other major outlays of funds.

Working capital requirements rose by $121 million as the higher crude oil and product costs were reflected in increased financing required for inventories and accounts receivable.

The net result of these changes was an increase in cash and marketable securities of $71 million.

Impact of inflation:

Gulf Canada's 1979 Annual Report provided information restated for changes in the purchasing power of the dollar. Presented below is another perspective of the impact of changing prices on earnings reflecting the increasing costs of replacement of inventories and property, plant and equipment, i.e., current costs.

In this context, Gulf Canada has estimated the approximate current cost of its property, plant and equipment by applying a variety of indices to the original cost of the assets. The Corporation has also approximated the impact of the increased cost to replace inventories at the date of sale.

The following table shows the approximate effects on reported 1980 after-tax earnings of $380 million if adjustments are made to reflect the impact of increasing costs on these items:

	Millions
Plant and Equipment	
Additional depreciation calculated on plant and equipment after restating their historical cost to current cost	$ 208
Inventories	
The additional cost of replacing goods sold	$ 130

The additional depreciation shown in the table above has been based on current cost methodology which assumes year-

end replacement of all existing fixed assets with like configuration. More likely, replacement assets would incorporate improved technology and operating efficiencies, thereby reducing the impact shown above. On the other hand, the cost of replacing oil and gas reserves by exploration in frontier areas or development of unconventional reserves would likely be in excess of their indexed amounts. Partially offsetting the impact shown in the above table, is the effect of financing during a period of inflation.

Theoretically, the Corporation gains during inflation when it has debt outstanding, since only the face amount of the debt has to be repaid and then only in dollars having a reduced purchasing power from when the liability was originally incurred. This gain, as measured by applying the change in the consumer price index to net liabilities, is estimated at $70 million.

The Canadian Institute of Chartered Accountants is in the process of studying responses to its 1979 Exposure Draft on Current Cost Accounting which recommended that public companies present supplementary information on a current cost basis. Also being considered, are the findings of a CICA Task Force which dealt with the special problems arising in applying current cost concepts to oil and gas resources.

Summary of Accounting Policies

The financial statements of the corporation have been prepared by management in accordance with accounting principles generally accepted in Canada. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of numerous estimates and approximations. The more significant of the corporation's accounting policies are summarized below.

Principles of consolidation:
The accounts of the corporation and all subsidiary companies are included in the financial statements. Investments in joint venture companies, owned 50 per cent or less, are accounted for on the equity basis. The corporation's proportionate share of assets and liabilities relating to the Syncrude project are included along with its share of production and costs from March 1, 1979.

Inventories:
Inventories of crude oil, products and merchandise are valued generally at the lower of cost applied on a "first-in, first-out" basis or market value determined on the basis of replacement cost or net realizable value.

Oil and gas properties:
The corporation follows the successful efforts method of accounting. The initial acquisition costs of oil and gas properties together with the costs of drilling and equipping development and successful exploratory wells, other than wells in certain frontier areas, are capitalized.

Exploration expenditures, including geological and geophysical costs, annual rentals on exploratory acreage and exploratory dry hole costs are charged to expense. In certain frontier areas, conditions are such that the future production from any reserves discovered is not reasonably assured because of environmental, technological or other constraints. In these areas, all expenditures including the cost of discovery wells, are charged to expense.

Depreciation, depletion and amortization:
Capitalized costs with respect to proved oil and gas properties are amortized against earnings on the unit-of-production method for each field using estimated proved recoverable oil and gas reserves. Charges are made against earnings for depreciation of investment in plant and equipment based on the estimated remaining useful lives of the assets using either the straight-line or the unit-of-production method, whichever is appropriate. Maintenance and repairs are charged to income, renewals and betterments, which extend the economic life of the assets, are capitalized.

Capitalized costs of unproved oil and gas properties are amortized on a group basis at a rate determined after considering past experience, lease terms and other relevant factors. No charges are made against earnings for the capitalized costs of certain in situ oil sands and coal properties pending further evaluation and development.

Assets retired or otherwise disposed of are removed from the accounts. Generally, the net capital gain or loss, after adjustment for salvage and dismantling expense, is included in earnings.

Capital leases:
Leases which transfer substantially all the benefits and risks of ownership of the

leased assets are capitalized. Capitalized leased assets are amortized against earnings based on their estimated useful lives. To December 31, 1980, such leases were not significant in relation to net assets and accordingly have not been shown separately on the statements of financial position.

Syncrude pre-production costs:
Prior to March 1, 1979, the corporation's share of all costs, net of revenues received, was capitalized and included with property, plant and equipment. Effective March 1, 1979, these capitalized pre-production costs are being amortized on a unit-of-production basis related to the corporation's share of the production and estimated recoverable reserves.

U.S. dollar liabilities:
Liabilities in U.S. dollars are translated to Canadian dollars at year-end rates of exchange. Gains or losses arising on translation of short-term liabilities are included in earnings. Unrealized gains or losses arising on translation of long-term liabilities are deferred and amortized over the remaining term of the liabilities.

Interest costs:
Interest costs are charged to income as incurred.

Research and development costs:
Research and development costs are charged to income as incurred.

Income taxes:
Income tax expense is computed on the basis of revenues and expenses reflected in the statement of earnings. A portion of such taxes is not currently payable as tax legislation permits the deduction of certain costs and allowances prior to the time they are recorded as expenses for financial statement purposes. The amount not currently payable is included in the statement of financial position as deferred income taxes.

Investment tax credits are applied to reduce the cost of the related fixed assets.

Pensions:
Pension benefit costs are determined annually by independent actuaries. The costs related to the current service of employees are charged to earnings. Costs resulting from amendments or upgrading of the plans, and which relate to service of employees in prior years, are amortized over the estimated remaining years of service of the employees involved.

Crude oil transactions:
In addition to its own net production, the corporation purchases crude oil from other producers and sells crude oil not required for its own refineries. These crude oil sales are reflected in the statement of earnings as a deduction from gross sales in determining net revenues. The amount shown in the statement of earnings for purchased crude oil is net of these crude oil sales. Sales of crude oil to the Alberta Petroleum Marketing Commission from April 1, 1980 are included in net sales and other operating revenues (see note 13).

Oil import compensation program:
Under the oil import compensation program the federal government compensates eligible importers with respect to petroleum imported for consumption in Canada, provided the importing company voluntarily maintains prices for products obtained from imported petroleum at the level suggested by the government. Compensation received or recoverable under this program is reflected as a reduction of the cost of purchased crude oil.
The federal government similarily compensates purchasers of synthetic crude oil produced from tar sands plants.

Consolidated Statements of Earnings

Gulf Canada Limited
Three Years Ended December 31, 1980

EARNINGS	**1980**	1979	1978
Revenues		*(millions of dollars)*	
Gross sales and other operating revenues	**$5,888**	$5,384	$4,665
Deduct—			
Crude oil sales	**(1,552)**	(2,077)	(1,797)
Taxes collected for governments	**(306)**	(300)	(317)
Net sales and other operating revenues (note 13)	**4,030**	3,007	2,551
Investment and sundry income (note 14)	**100**	51	33
Net revenues	**4,130**	3,058	2,584
Expenses			
Purchased crude oil, products and merchandise net of crude oil sales (note 13)	**1,844**	1,406	1,328
Operating expenses	**446**	372	266
Exploration, dry hole and frontier area expenditures	**246**	166	115
Selling and administrative expenses	**431**	355	328
Taxes other than taxes on income (note 15)	**326**	190	140
Income taxes (note 16)	**290**	147	105
Depreciation, depletion and amortization	**141**	123	89
Interest on long-term debt	**26**	25	26
	3,750	2,784	2,397
Earnings for the year before Syncrude gain	**380**	274	187
Gain on sale of portion of Syncrude interest (note 17)		14	
Earnings for the year	**$ 380**	$ 288	$ 187
Earnings per share	**$1.67**	$1.27	$ .82

RETAINED EARNINGS			
Balance, beginning of the year	**$1,234**	$1,138	$1,003
Add earnings for the year	**380**	288	187
	1,614	1,426	1,190
Deduct— Dividends	**93**	68	52
— Excess of consideration applicable to shares received and cancelled over their average paid in value (note 11)		124	
Balance, end of the year	**$1,521**	$1,234	$1,138

(See accompanying notes to consolidated financial statements)

Consolidated Statements of Financial Position

Gulf Canada Limited
December 31, 1980 and 1979

ASSETS	**1980**	1979
Current	*(millions of dollars)*	
Cash and term deposits	**$ 73**	$ 52
Marketable securities, at cost (approximates market value)	**298**	248
Accounts receivable (notes 2 and 7)	**730**	706
Inventories (note 3)	**661**	543
Materials, supplies and prepaid expenses	**64**	52
Total current assets	**1,826**	1,601
Investments, long-term receivables and other assets (note 4)	**107**	87
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization (note 5)	**1,759**	1,607
	$3,692	$3,295

LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Short-term loans (note 6)	**$ 18**	$ 23
Accounts payable (note 7)	**538**	595
Income and other taxes payable	**227**	173
Dividends payable	**25**	18
Other current liabilities	**128**	94
Total current liabilities	**936**	903
Long-term debt (note 8)	**315**	333
Deferred gas production revenue (note 9)	**72**	37
Deferred income taxes	**443**	383
Shareholders' equity:		
Capital stock (note 10)	**405**	405
Retained earnings	**1,521**	1,234
Total shareholders' equity	**1,926**	1,639
	$3,692	$3,295

(See accompanying notes to consolidated financial statements)

On behalf of the Board:

J.L. Stoik, Director

Alfred Powis, Director

Consolidated Statements of Changes in Financial Position

Gulf Canada Limited
Three Years Ended December 31, 1980

SOURCE OF FUNDS		**1980**	1979	1978
			(millions of dollars)	
Earnings for the year		**$380**	$288	$187
Income charges (credits) not affecting funds—				
Depreciation, depletion and amortization		**141**	123	89
Deferred income taxes		**60**	28	71
Other		**(39)**	(29)	2
From operations		**542**	410	349
Add exploration expenditures		**246**	166	115
From operations before exploration expenditures		**788**	576	464
Sales of properties and investments		**26**	21	21
Sale of assets to Petromont consortium (note 14)	**$43**			
Less amount representing investment in the consortium	**(13)**	**30**		
Sale of portion of Syncrude interest			91	
Long-term debt			2	34
Deferred gas production revenue (note 9)		**35**	24	13
		879	714	532
USE OF FUNDS				
Additions to property, plant and equipment		**326**	244	370
Exploration expenditures		**246**	166	115
Total capital expenditures		**572**	410	485
Reduction in long-term debt		**18**	18	37
Dividends		**93**	68	52
Advance funding of pensions			10	
Other (net)		**4**	1	2
		687	507	576
Increase (decrease) in working capital		**$192**	$207	$(44)
WORKING CAPITAL CHANGES				
Cash and term deposits		**$ 21**	$ 33	$ (7)
Marketable securities		**50**	114	(14)
Accounts receivable and other		**24**	174	5
Inventories		**118**	150	(83)
Materials, supplies and prepaid expenses		**12**	13	9
Accounts payable and other		**21**	(171)	48
Income and other taxes payable		**(54)**	(106)	(2)
Increase (decrease) in working capital		**192**	207	(44)
Working capital, beginning of the year		**698**	491	535
Working capital, end of the year		**$890**	$698	$491

(See accompanying notes to consolidated financial statements)

Notes to Consolidated Financial Statements

Gulf Canada Limited
December 31, 1980

1. Accounting policies
The more significant of the corporation's accounting policies are summarized on pages 35 and 36 of this report.

2. Accounts receivable	**1980**	1979
	(millions of dollars)	
Customers	**$591**	$580
Other receivables	**149**	135
	740	715
Less allowance for doubtful accounts	**10**	9
	$730	$706

3. Inventories	**1980**	1979
First-in, first-out	*(millions of dollars)*	
Crude oil and other source materials	**$216**	$159
Refined products and chemicals	**445**	384
	$661	$543

The inventory amounts included in purchased costs used in the computation of cost of sales were (in millions of dollars): December 31, 1980 — $661; 1979 — $543; 1978 — $393.

4. Investments, long-term receivables and other assets	**1980**	1979
Investments in associated and other companies	*(millions of dollars)*	
At cost:		
With quoted market value (based on closing prices at end of each year) 1980 — $38 million; 1979 — $43 million	**$ 3**	$ 3
At equity:		
Investment in joint venture companies, at cost plus equity in undistributed earnings	**34**	15
	37	18
Long-term receivables and other assets	**70**	69
	$107	$87

5. Property, plant and equipment

	Range of depreciation rates	**Gross investment at cost (1)**	**Accumulated depreciation, depletion and amortization**	**Net investment 1980**	Net investment 1979
Natural resources		*(millions of dollars)*			
Exploration and production	(2)	**$1,042**	**$ 436**	**$ 606**	$ 486
Syncrude project	(2)	**306**	**18**	**288**	287
In situ oil sands and coal	(3)	**113**	**13**	**100**	75
		1,461	**467**	**994**	848
Refined products					
Transportation	4%–10%	**57**	**29**	**28**	29
Refining	(4)	**756**	**367**	**389**	379
Marketing	2.5%–10%	**390**	**170**	**220**	207
		1,203	**566**	**637**	615
Chemicals	(4)	**55**	**36**	**19**	48
Other	2.5%–10%	**128**	**19**	**109**	96
		$2,847	**$1,088**	**$1,759**	$1,607

(1) Additions during the year have been reduced by investment tax credits of (millions of dollars): 1980 — $9; 1979 — $5; 1978 — $8.
(2) Unit of production.
(3) No charges are made against earnings for the acquisition costs of these properties pending further evaluation and development; cost of equipment used in research and testing activities on these properties is depreciated over the life of the related activities.
(4) Processing units on unit of production, other items from 2.5 per cent to 10 per cent.

6. Short-term loans

The weighted average interest rates of short-term loans at December 31, 1980, 1979 and 1978, respectively were 12.78 per cent, 11.97 per cent, and 8.45 per cent. Average aggregate short-term loans outstanding: 1980, $25 million; 1979, $18 million; and 1978, $28 million. The maximum aggregate amount outstanding at any month end during 1980 was $36 million; in 1979, $25 million; and in 1978, $35 million.

At December 31, 1980, the corporation had lines of credit available in the amount of $200 million. These lines have been renewed annually on May 31, and any borrowing under these lines of credit would bear interest at the prime rate.

7. Material transactions with related parties

Included in accounts receivable and accounts payable are amounts receivable from and owing to Gulf Oil Corporation and its subsidiaries, all of which arose in the normal course of business, of $16 million and $5 million, respectively, at December 31, 1980 ($7 million and $107 million, respectively, at December 31, 1979).

The more significant of the transactions the corporation has with Gulf Oil Corporation and its affiliates are for the purchase and sale of crude oil, refined products and petrochemicals; the receipt of technical and engineering services under research agreements; and hiring ocean tank vessels. The aggregate net amount paid or payable by the corporation in this connection, principally covering crude oil purchases was (millions of dollars): 1980 – $232; 1979 – $515; 1978 – $258. See also note 11 with respect to a transaction with a subsidiary of Gulf Oil Corporation.

8. Long-term debt	**1980**	1979
	(millions of dollars)	
5¾% Series B sinking fund debenture payable through 1982 to 1990	**$ 2**	$ 2
5¼% Series C sinking fund debenture payable through 1982 (1)	**4**	6
7⅜% Series E sinking fund debenture payable through 1988	**28**	30
8½% sinking fund debenture payable through 1989	**3**	3
8½% sinking fund debenture payable through 1990	**3**	3
8⅛% loan re Syncrude payable 1984 through 1994 (2)	**119**	119
8⅜% notes payable through 1997 (1)	**149**	146
Other long-term obligations payable on varying dates	**25**	39
	333	348
Less instalments due within one year included in current liabilities	**18**	15
	$315	$333

(1) These are payable in U.S. dollars. The amounts outstanding in U.S. dollars at December 31, 1980 are: 5¼% Series C debenture – $4 million, 8⅜% notes – $125 million (1979 – $5 million and $125 million, respectively).

(2) The 8⅛% loan from the Government of Alberta, which includes accrued interest of $19 million at December 31, 1980 and 1979, is evidenced by a debenture convertible by the holder into a portion of the corporation's equity interest in the Syncrude Project. (See note 12.) To the extent that the loan is converted, a proportionate amount of accrued interest will be forgiven.
In the event that the conversion option is not exercised, the loan plus accrued interest is repayable in ten equal annual instalments commencing March 1, 1985.

Approximate annual instalments of long-term debt due in the next five years are (millions of dollars): 1981 – $18; 1982 – $9; 1983 – $10; 1984 – $11; 1985 – $21.

9. Deferred gas production revenue

Deferred gas production revenue represents payments received under "take or pay" gas contracts. These amounts will be included in revenue when the gas to which the payments relate is delivered at the option of the purchaser. These amounts are shown as long-term since under current economic conditions the gas due under the take or pay contracts is not expected to be delivered within the next few years. Payments received in prior years and included in current liabilities in those years have been reclassified as long-term.

10. Capital stock

Shares without nominal or par value

Authorized:

Common—unlimited number without nominal or par value;

Preferred—unlimited number without nominal or par value. The preferred shares shall rank in priority to the common shares and may be issued from time to time in series with the designation, rights, restrictions, conditions and limitations of each series as may be fixed before their issuance by the directors.

Issued:

Common—the following is an analysis of the capital stock account for the years ended December 31, 1980 and 1979.

	Shares*	Millions of dollars
December 31, 1977 and 1978	227,487,030	$281
Add issued in respect of investment in Amalgamated Bonanza (note 11)	8,238,190	139
Less received and cancelled in respect of sale of investment in Amalgamated Bonanza (note 11)	(8,238,190)	(15)
December 31, 1979 and 1980	227,487,030	$405

*Adjusted to reflect the five-for-one split effective May 6, 1980.

11. Amalgamated Bonanza

In 1979 the corporation entered into an agreement to acquire for sale to Transocean Gulf Oil Company (Transocean), a subsidiary of Gulf Oil Corporation, all the outstanding shares of Amalgamated Bonanza Petroleum Ltd. ("Amalgamated Bonanza"). The transaction resulted in the corporation issuing common shares and paying cash for the purchase of Amalgamated Bonanza and subsequently receiving from Transocean an equal number of common shares and an equal amount of cash for the sale of Amalgamated Bonanza. The common shares received were cancelled. The total consideration in respect of the shares received and cancelled amounted to $139 million; of this amount, $15 million represented the average paid-in value of the common shares and was deducted from capital stock; the balance of $124 million was deducted from retained earnings. Transocean also paid the corporation an amount of $5 million when the transaction was closed and this is included in 1980 earnings.

12. Syncrude

The corporation is a 13.4 per cent participant in the Syncrude project constructed and operated by Syncrude Canada Ltd. to produce synthetic crude oil from oil sands in the Athabasca region of Alberta.

Part of the corporation's interest in the project was financed through a $100 million convertible loan from the Government of Alberta. For a period of five years from March 1, 1979 the Government of Alberta can convert all or part of the principal amount into an equity interest in the project based on the relationship of the amount converted to the total project costs. Should this option be exercised to the maximum extent, Gulf Canada's interest would be reduced to nine per cent.

13. Crude oil sales and purchases

Effective April 1, 1980, all of Gulf Canada's production from crown leases in Alberta has been recorded as a sale to the Alberta Petroleum Marketing Commission following the Commission's decision to utilize its legislative mandate and assume control of the distribution of all crude oil produced in the province from crown lands. Concurrently, the calculation for the elimination of inter-company profit on the company's own crude oil production in inventory was revised to take into account the changed patterns of crude oil trading and to eliminate only the profit on production from its freehold lands. These changes, which have no material effect on earnings, have resulted in an increase in "Net sales and other operating revenues" of approximately $168 million for the year ended December 31, 1980, with a corresponding increase in "Purchased crude oil" to reflect purchases from the Commission.

14. Sale of certain petrochemical assets

On September 30, 1980, the corporation entered into agreements with Union Carbide Canada Limited and the Government of Quebec to form a major petrochemical consortium in the Montreal area, with operations commencing on October 1, 1980. This project involved the transfer by the corporation of certain assets for cash and a 49 per cent participation in the project which, under the agreements, will be reduced to 33.33 per cent by October, 1982. The transfer of assets resulted in the recognition of a gain in 1980 of $17 million before income taxes ($11 million after tax). The pre-tax gain is included in investment and sundry income.

15. Taxes other than taxes on income	**1980**	1979	1978
		(millions of dollars)	
Production, transportation and usage taxes	**$121**	$ 97	$ 97
Petroleum Administration Act Levy	**155**	52	5
Property and other taxes	**50**	41	38
	$326	$190	$140

16. Income tax

Total income tax expense as reflected in the statement of earnings represents the effective tax rate which differs from combined federal and provincial statutory tax rates. The main differences are shown in the table below:

	1980		1979		1978	
			(millions of dollars)			
	Amount	**%**	Amount	%	Amount	%
Provision for income taxes at statutory rates	**$334**	**50%**	$202	48%	$141	48%
Add (deduct) the tax effect of—						
Inclusion in taxable income of crown royalties and other provincial payments	**142**	**21**	113	27	99	34
Resource allowance to partially offset inclusion of crown royalties	**(118)**	**(18)**	(90)	(22)	(74)	(25)
Depletion allowance earned by exploration and development expenditures	**(38)**	**(6)**	(42)	(10)	(37)	(13)
Frontier exploration allowance earned by frontier drilling expenditures (expired on March 31, 1980)	**(7)**	**(1)**	(22)	(5)	(11)	(4)
Inventory allowance to partially offset the effect of inflation	**(8)**	**(1)**	(6)	(1)	(7)	(2)
Manufacturing and processing incentive	**(8)**	**(1)**	(3)	(1)	—	—
Other	**(7)**	**(1)**	(5)	(1)	(6)	(2)
Provision for income taxes reflected in the statement of earnings	**$290**	**43%**	$147	35%	$105	36%

Income taxes include deferred income taxes of $60 million in 1980, $28 million in 1979 and $71 million in 1978. These deferred income taxes are related primarily to the excess of capital cost allowances claimed for tax purposes over depreciation recorded in the accounts.

17. Gain on sale of portion of Syncrude interest

In 1979, the Alberta Energy Company Ltd. exercised its option to acquire 20 per cent of the interest of all the participants in the Syncrude project. This disposition by the corporation of a 3.35 per cent interest in the Syncrude project resulted in a gain of $14 million after the deduction of income taxes of $5 million.

18. Pension plans

The corporation has pension plans covering substantially all employees. The contributions by employees, together with those made by the corporation, are deposited with insurance companies and/or trustees according to the terms of the plan. Pensions at retirement are related to remuneration and years of service.

The amounts charged to earnings (including amounts paid to government pension plans and the amortization of prior service costs) were (millions of dollars): 1980—$36; 1979—$28; 1978—$20.

As of December 31, 1980, the actuarial present values of accumulated plan benefits using an actuarial rate of return of 5¼ per cent, were (millions of dollars):

Vested	$291
Non-vested	18
Total unamortized	$309

As of December 31, 1980, the plan's net assets, valued at cost, available for benefits amounted to $228 million (at market—$250 million).

The unamortized prior service costs at December 31, 1980 were approximately $90 million which consisted of (millions of dollars):

Amounts not yet funded	$ 81
Amount funded and deferred in the accounts	9
Total	$ 90

The plans were further amended on January 1, 1981, primarily to provide for retirement benefits based on a final earnings formula. The amendments increased the actuarial present value of accumulated plan benefits (and the unfunded and unamortized prior service costs) by $123 million which will be funded and amortized over 15 years.

The unamortized costs of $213 million will be charged to earnings over periods up to 15 years. The unfunded amount of $204 million, of which approximately $69 million represents the excess of the actuarially computed value of vested benefits over the assets of the plans, will be funded over periods up to 15 years.

19. Supplementary information to the consolidated statement of earnings	**1980**	1979	1978
	(millions of dollars)		
Research and development	**$ 45**	$ 31	$ 30
Maintenance and repairs	**136**	106	82
Operating lease rentals	**62**	54	49
Interest on short-term loans	**3**	2	2

20. Commitments and contingent liabilities

The corporation has commitments in the ordinary course of business (for the acquisition, construction or rental of properties and the purchase of materials and services) and contingent liabilities under various guarantees, all of which are not significant in relation to net assets.

21. Segment data

Business segment data for the corporation are shown in the following table. This information by segment is shown as though each segment were a separate business activity. Therefore, intersegment transfers of products are eliminated to reflect total corporation net revenues as reported in the consolidated statements of earnings.

The natural resources segment includes exploration, development and production activities related to crude oil, natural gas, natural gas liquids, oil sands and minerals. The refined products segment includes the manufacture, distribution and sale of petroleum products, as well as the business of Superior Propane Limited, a wholly-owned subsidiary. The chemicals segment includes the manufacture, distribution and sale of chemical products, as well as the corporation's share of the earnings from the Petromont consortium.

General administration and other common costs have been allocated to each of the segments on an appropriate and consistent basis and income taxes have been calculated in accordance with the legislation applicable to each segment. Interest on long-term liabilities has not been allocated to the business segments and is shown separately net of tax.

Revenues	1980	1979	1978
Natural resources		*(millions of dollars)*	
Outside the enterprise	**$ 560**	$ 305	$ 250
Intersegment revenues	**512**	551	369
Total natural resources	**1,072**	856	619
Refined products			
Outside the enterprise	**3,184**	2,433	2,111
Intersegment revenues	**136**	140	115
Total refined products	**3,320**	2,573	2,226
Chemicals			
Outside the enterprise	**275**	225	156
Intersegment revenues	**24**	29	22
Total chemicals	**299**	254	178
Corporate and other			
Outside the enterprise	**111**	95	67
Elimination of intersegment revenues	**(672)**	(720)	(506)
Total segment revenues	**$4,130**	$3,058	$2,584

Earnings	1980	1979	1978
Natural resources		*(millions of dollars)*	
Operating profits	**$344**	$313	$263
General corporate expenses	**(11)**	(8)	(5)
Income taxes	**(141)**	(104)	(103)
Net segment earnings—natural resources	**192**	201	155
Refined products			
Operating profits	**297**	115	67
General corporate expenses	**(48)**	(35)	(32)
Income taxes	**(113)**	(30)	(11)
Net segment earnings—refined products	**136**	50	24
Chemicals			
Operating profits	**67**	44	13
Gain on sale of chemical assets	**17**	—	—
General corporate expenses	**(6)**	(4)	(4)
Income taxes	**(35)**	(18)	(3)
Net segment earnings—chemicals	**43**	22	6
Corporate and other			
Operating profits	**39**	32	18
Income taxes	**(14)**	(10)	(1)
Net segment earnings—corporate and other	**25**	22	17
Eliminations			
Operating profits	**(3)**	(11)	(2)
Income taxes	**1**	4	—
Net eliminations	**(2)**	(7)	(2)
Net segment earnings	**394**	288	200
Gain on sale of portion of Syncrude interest (after tax)	**—**	14	—
Interest on long-term debt after tax	**(14)**	(14)	(13)
Net earnings for the year	**$380**	$288	$187

Asset Data	**1980**	1979	1978
Assets employed at December 31	*(millions of dollars)*		
Identifiable assets			
Natural resources	**$1,158**	$ 991	$ 944
Refined products	**1,925**	1,759	1,480
Chemicals	**80**	102	125
Eliminations	**(41)**	(37)	(27)
Total identifiable assets	**3,122**	2,815	2,522
Corporate assets	**570**	480	239
Total assets	**$3,692**	$3,295	$2,761
Capital and exploration expenditures			
Additions to property, plant and equipment			
Natural resources	**$ 214**	$ 128	$ 235
Refined products	**89**	43	105
Chemicals	**5**	4	19
Corporate and other	**18**	69	11
Total	**326**	244	370
Exploration expenditures	**246**	166	115
Total capital and exploration expenditures	**$ 572**	$ 410	$ 485
Depreciation, depletion and amortization			
Natural resources	**$ 66**	$ 52	$ 33
Refined products	**63**	58	48
Chemicals	**8**	10	6
Corporate and other	**4**	3	2
Total depreciation, depletion and amortization	**$ 141**	$ 123	$ 89

Auditors' Report

To the Shareholders of
Gulf Canada Limited:

We have examined the consolidated statements of financial position of Gulf Canada Limited as at December 31, 1980 and 1979 and the consolidated statements of earnings and changes in financial position for the three years ended December 31, 1980. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the corporation as at December 31, 1980 and 1979 and the results of its operations and the changes in its financial position for the three years ended December 31, 1980 in accordance with generally accepted accounting principles consistently applied.

Toronto, Canada,

February 10, 1981

Clarkson Gordon
Chartered Accountants

Quarterly Summary 1980

	1	2	3	4	Year
FINANCIAL (1)			*(millions of dollars)*		
Net revenue	909	957	1,054	1,210	4,130
Earnings before income tax	152	165	176	177	670
Net earnings	91	95	100	94	380
Per common share *(dollars per share)*	0.40	0.42	0.44	0.41	1.67
OPERATING			*(thousands of cubic metres per day)*		
Gross crude oil and natural gas liquids produced	22.8	20.4	19.1	20.2	20.6
Gross synthetic crude oil produced	0.6	2.3	2.2	1.9	1.7
Gross natural gas produced and sold *(millions)*	11.2	8.6	6.6	9.5	8.9
Crude oil processed	49.2	46.0	44.2	44.8	46.1
Petroleum products sold	44.0	38.2	41.1	47.6	42.7
Chemical products sold *(millions of kilograms)*	1.4	1.4	1.5	0.6(4)	1.3
SHAREHOLDERS' STATISTICS (2)			*(dollars per share)*		
Equity per share—book value	7.53	7.83	8.16	8.47	8.47
Market value per share:					
Toronto Stock Exchange					
—High	38⅝	35	36⅛	33¾	38⅝
—Low	20⅛	25½	26½	19⅞	19⅞
—Close	25⅞	33	28⅛	23⅜	23⅜
Dividends declared	0.08	0.11	0.11	0.11	0.41
Cash flow per share	0.59	0.64	0.55	0.60	2.38
Price/earnings ratio at quarter-end (5)	16	20	16	14	14
Shareholders at quarter-end *(thousands)*	21.8	30.5	35.0	39.9	39.9
Shares traded *(millions)*	66.0	40.0	33.4	48.7	188.1

Quarterly Summary 1979

	1	2	3	4	Year
FINANCIAL (1)			*(millions of dollars)*		
Net revenue	705	675	783	895	3,058
Earnings before income tax	84	83	144	129	440
Net earnings	53	54	99(3)	82	288
Per common share *(dollars per share)*	0.23	0.24	0.44(3)	0.36	1.27
OPERATING			*(thousands of cubic metres per day)*		
Gross crude oil and natural gas liquids produced	20.3	22.5	21.1	22.1	21.5
Gross synthetic crude oil produced	1.0	1.0	1.3	1.0	1.1
Gross natural gas produced and sold *(millions)*	11.9	10.9	9.9	11.2	11.0
Crude oil processed	48.5	49.8	49.8	54.4	50.6
Petroleum products sold	44.9	38.4	43.0	45.3	42.9
Chemical products sold *(millions of kilograms)*	1.4	1.2	1.5	1.5	1.4
SHAREHOLDERS' STATISTICS (2)			*(dollars per share)*		
Equity per share—book value	6.40	6.57	6.92	7.20	7.20
Market value per share:					
Toronto Stock Exchange					
—High	10	12¾	21⅛	25	25
—Low	7⅛	9	10⅝	16⅜	7⅛
—Close	9½	11½	19¾	22⅜	22⅜
Dividends declared	0.07	0.07	0.08	0.08	0.30
Cash flow per share	0.43	0.41	0.49	0.47	1.80
Price/earnings ratio at quarter-end (5)	10	12	16	18	18
Shareholders at quarter-end *(thousands)*	19.7	20.3	19.6	18.9	18.9
Shares traded *(millions)*	6.9	12.0	51.0	53.5	123.4

(1) Quarterly information is unaudited.
(2) Restated to reflect the 5-for-1 split of common shares effective May, 1980.
(3) Includes gain on sale of Syncrude interest of $14 million or $.06 per share.
(4) Reflects sale of the Varennes plant to the Petromont consortium.
(5) Closing share price divided by annualized earnings.

Management Discussion and Analysis

Management discussion and analysis of financial conditions and results of operations.

Revenue Trends

	1980	1979	1978	**1980/79**	1979/78
	(millions of dollars)			*(per cent increase)*	
Natural resources—					
Natural gas	**$ 304**	$ 264	$ 220	**15**	20
Crude oil and natural gas liquids	**443**	185	152	**139**	22
Refined products—					
Gasoline	**1,227**	972	825	**26**	18
Middle distillates	**841**	657	570	**28**	15
Other	**636**	483	429	**32**	13
Chemicals	**269**	230	160	**17**	44
Other operating revenue	**310**	216	195	**44**	11
Total operating revenue	**$4,030**	$3,007	$2,551	**34**	18

This table shows the trends in revenues for the years 1978 through 1980 and the year-to-year increases.

Natural gas revenues have risen mainly as a result of price increases. Sales volumes increased marginally in 1979 but showed a sharp decline of 19 per cent in 1980 due to price resistance in export markets and oversupply conditions. Approximately 20 per cent of Gulf Canada's natural gas production capacity is shut in.

Crude oil and natural gas liquid sales in 1980 include $168 million relating to crude oil sold to the Alberta Petroleum Marketing Commission (APMC) following the Commission's decision, effective April 1, 1980, to control all crude oil production from Crown Lands in Alberta. (See note 13 in "Notes to consolidated financial statements"). The remaining 1980 revenue increase over 1978 reflects higher natural gas liquids selling prices.

Revenue from refined products rose over the period 1978-80, mainly due to price firming across Canada. Improved market conditions are the result of a shift from oversupply conditions in 1978 to tight supply beginning in late 1979. Volumes in total have remained stable.

Chemical revenues also rose during the period 1978-80, reflecting higher prices in response to tight olefin markets and increasing crude oil feedstock costs. Only in the last quarter of 1980 did chemical revenues decline, reflecting a change to equity basis accounting following the sale of the Varennes plant to the Petromont consortium in exchange for a 49 per cent equity interest. Since the sale, the Corporation has accounted for its share of the earnings of the consortium in investment and sundry income. By October, 1982, the Corporation's investment in the consortium will be reduced to 33.3 per cent.

Other operating revenue increased in 1980 due mainly to the higher compensation received from the federal government to reflect world crude oil prices for production from the Syncrude project.

Cost/Revenue Relationships

	1980	1979	1978	**1980/79**	1979/78
	(per cent of net revenues)			*(per cent increase)*	
Purchased crude oil, products and merchandise net of crude oil sales	**46**	47	52	**31**	6
Operating, depreciation, depletion and amortization costs	**15**	17	14	**19**	39
Exploration, dry hole and frontier area expenditures	**6**	5	5	**48**	44
Selling and administrative expenses	**11**	12	14	**21**	8
Taxes other than taxes on income	**8**	6	5	**72**	36
Income from operations	**14**	13	10	**54**	43
Investment and other income	**2**	2	1	**54**	97
Income before taxes	**16**	15	11	**54**	49
Income taxes	**7**	5	4	**97**	40
Earnings for the year	**9**	10	7	**32**	54

This table shows cost trends as a percentage of net revenues for the years 1978 through 1980 and the year-to-year percentage changes in costs.

Purchased crude oil, products and merchandise net of crude oil sales have declined as a percentage of net revenue, reflecting the increased production of crude oil from Gulf Canada's reserves since 1978. At the same time, total purchase costs rose, mainly due to increases in crude oil prices and the recording of purchases from the APMC for the first time in 1980.

Operating expenses and depreciation, depletion and amortization costs remained relatively unchanged as a percentage of net revenue. In total, these costs increased year over year due to rising production levels in 1979 and 1980, additional capital investment during the period, and inflation. The 1979 high of 17 per cent reflected the Syncrude project and Clarkson lube plant both of which began production during 1979, and which were affected by start-up problems.

Exploration, dry hole and frontier costs remained relatively stable as a percentage of net revenue. However, the level of such costs escalated significantly each year, reflecting both increased activity and the higher cost of drilling, particularly in the Beaufort Sea and east coast offshore areas.

Selling and administrative expenses declined as a percentage of net revenue but increased significantly in 1980 in absolute terms due primarily to higher distribution costs.

Taxes, other than taxes on income, have been increasing as a percentage of net revenue reflecting mainly the significant increases in the Petroleum Compensation Charge (previously known as the Syncrude levy) and higher federal sales tax.

In summary, during the period 1978 through 1980, higher prices, firmer markets and greater crude production outpaced rising costs of operations, and resulted in income from operations increasing as a percentage of net revenue. Other income has more than doubled in the period, reflecting the increased earnings from equity and associated companies, higher interest income from short-term investments, and the gain on the sale of the Varennes plant in 1980.

Income taxes have almost doubled as a percentage of net revenues in the period, and more than doubled in absolute terms as a result of increased taxable income, a five per cent federal surtax in 1980, higher royalties which are not allowable for federal tax purposes, and the expiration of super depletion allowance from March 31, 1980.

Liquidity and Capital Commitments

Internal cash flow covered all capital requirements in 1979 and 1980. In 1980 working capital increased by $192 million to $890 million, and long-term debt declined by $18 million. Cash and marketable securities total $371 million at the end of 1980. In addition, the Corporation maintains lines of credit totalling $200 million. These credit lines have been renewed annually on May 31 and any related borrowings would bear interest at the prime rate. Interest coverage was 27 times earnings at the end of 1980. Long-term debt was 14 per cent of total capitalization at December 31, 1980.

The federal government introduced a national energy program for Canada on October 28, 1980. If implemented, the impact of this policy on foreign-owned corporations such as Gulf Canada will be significant as the provisions include an eight per cent tax on all oil and gas net production revenues and relate exploration incentives to the percentage of Canadian ownership of a particular corporation. The impact of the energy policy falls almost entirely on Gulf Canada's natural resource segment and is expected to reduce internal cash flow by approximately 30 per cent over the next five years from previously anticipated levels. More than half the decline will result from the eight-per-cent tax on production revenues, and approximately one-third from the phasing-out by 1983 of the earned depletion allowance. If the eight-per-cent tax had been in effect during 1980, the negative impact on earnings would have been $77 million.

Gulf Canada anticipates capital and exploration expenditures will approach $900 million in 1981, an increase of $328 million or 57 per cent over 1980. Of this, approximately two-thirds is planned for the natural resources segment and the remainder in the refined product and chemicals segments. This represents a change from 1980 when 80 per cent of the capital expenditures were for the resources segment. The shift is mainly due to a reduction from previously-planned resource spending in response to the National Energy Program. It is anticipated that internal cash flows, together with funds available at the end of 1980, will be sufficient to cover 1981 expenditures. In October, 1980, the Corporation filed preliminary prospectuses with regulatory authorities in Canada and the United States relating to proposed issues of long-term debentures in one or both jurisdictions depending on market conditions. The Corporation will proceed with external financing in 1981 only if capital markets improve.

Five Year Financial Summary

STATEMENT OF EARNINGS	**1980**	1979	1978	1977	1976
REVENUES			*(millions of dollars)*		
Natural gas	**$ 304**	$ 264	$ 220	$ 207	$ 173
Crude oil and natural gas liquids	**443**	185	152	146	144
Refined products					
– gasoline	**1,227**	972	825	721	589
– middle distillates	**841**	657	570	519	417
– other	**636**	483	429	411	311
Chemicals	**269**	230	160	137	126
Other operating revenue	**310**	216	195	181	164
Net sales and other operating revenues	**4,030**	3,007	2,551	2,322	1,924
Investment and sundry income	**100**	51	33	35	30
Net revenues	**4,130**	3,058	2,584	2,357	1,954
EXPENSES					
Purchased crude oil, products and merchandise net of crude oil sales	**1,844**	1,406	1,328	1,196	933
Operating expenses	**446**	372	266	228	201
Exploration, dry hole and frontier area expenditures	**246**	166	115	111	62
Selling and administrative expenses	**431**	355	328	300	276
Taxes other than taxes on income	**326**	190	140	125	111
Income taxes	**290**	147	105	110	123
Depreciation, depletion and amortization	**141**	123	89	82	73
Interest on long-term debt	**26**	25	26	21	8
	3,750	2,784	2,397	2,173	1,787
Earnings for the year before Syncrude gain	**380**	274	187	184	167
Gain on sale of portion of Syncrude interest	**—**	14*	—	—	—
Earnings for the year	**$ 380**	$ 288	$ 187	$ 184	$ 167
PER SHARE**					
Earnings	**$ 1.67**	$ 1.27	$ 0.82	$ 0.81	$ 0.73
Dividends declared	**$ 0.41**	$ 0.30	$ 0.23	$ 0.22	$ 0.20

*After deduction of $5 million income taxes.

**Years 1976–1979 have been restated for five-for-one split of common stock effective May, 1980.

STATEMENT OF FINANCIAL POSITION					
			(millions of dollars)		
Current assets	**$1,826**	$1,601	$1,117	$1,207	$ 980
Current liabilities	**936**	903	626	672	508
Working capital	**890**	698	491	535	472
Investments and other assets	**107**	87	81	70	56
Net property, plant and equipment	**1,759**	1,607	1,567	1,296	1,009
Capital employed	**2,756**	2,392	2,139	1,901	1,537
Long-term debt	**315**	333	350	333	167
Deferred gas production revenue	**72**	37	13	—	—
Deferred income taxes	**443**	383	357	284	221
Shareholders' equity (net assets)	**$1,926**	$1,639	$1,419	$1,284	$1,149
Total assets	**$3,692**	$3,295	$2,765	$2,573	$2,045

STATEMENT OF CHANGES IN FINANCIAL POSITION	1980	1979	1978	1977	1976
SOURCES OF FUNDS			(millions of dollars)		
From operations	$ 542	$ 410	$ 349	$ 332	$ 278
Exploration expenditures	246	166	115	111	62
Funds from operations before exploration expenditures	788	576	464	443	340
Sales of properties and investments	56	21	21	17	11
Sale of portion of Syncrude	—	91	—	—	—
Deferred gas production revenue	35	24	13	—	—
Long-term debt	—	2	34	180	66
Total sources of funds	879	714	532	640	417
USES OF FUNDS					
Capital and exploration expenditures	572	410	485	494	323
Reduction of long-term debt	18	18	37	31	17
Dividends	93	68	52	49	46
Advance funding of pensions	—	10	—	—	—
Other—net	4	1	2	3	(2)
Total uses of funds	687	507	576	577	384
Increase (decrease) in working capital	$ 192	$ 207	$ (44)	$ 63	$ 33

Financial Ratios

	1980	1979	1978	1977	1976	1975	1974	1973	1972	1971
Return on capital employed (1)	15.3%	13.3%	9.9%	11.4%	11.9%	14.5%	14.7%	10.1%	7.1%	4.8%
Return on shareholders' equity (2)	21.3%	18.8%	13.8%	15.1%	15.3%	18.3%	19.3%	13.1%	8.9%	5.8%
Current ratio (3)	2.0	1.8	1.8	1.8	1.9	2.1	1.8	2.4	2.6	2.1
Long-term debt to total capitalization (4)	14%	17%	20%	18%	13%	10%	10%	19%	21%	22%
Earnings coverage of interest (5)	27x	18x	12x	15x	37x	36x	25x	12x	7x	6x
Reinvestment ratio (6)	89%	78%	99%	119%	91%	115%	62%	29%	62%	88%

Definitions

(1) Return on capital employed: Net after-tax earnings plus after-tax interest expense as a percentage of average capital employed for the year. Capital employed is calculated by deducting current liabilities from total assets.

(2) Return on shareholders' equity: Net after-tax earnings as a percentage of average shareholders' equity for the year. Shareholders' equity is composed of the book value of common shares outstanding and retained earnings.

(3) Current ratio: Ratio of total current assets to total current liabilities.

(4) Long-term debt to total capitalization: Long-term debt as a percentage of total assets less current liabilities.

(5) Earnings coverage of interest: Pre-tax earnings and pre-tax interest expense as a multiple of pre-tax interest expenses.

(6) Reinvestment ratio: The total of capital and exploration expenditures and the increase or decrease in non-cash working capital as a per cent of the total of net earnings, exploration expenditures, depreciation and depletion allowances and deferred taxes.

Five Year Operations Review

	1980	1979	1978	1977	1976
Crude Oil and Natural Gas Liquids (1)		*(thousands of cubic metres)*			
Gross production – year	**7,552**	7,858	6,492	6,682	6,886
– per day	**20.6**	21.5	17.8	18.3	18.8
Net production – year	**5,061**	5,379	4,334	4,426	4,697
– per day	**13.8**	14.8	11.9	12.1	12.9
Net reserves	**35,600**	38,600	40,700	47,100	50,200
Natural Gas		*(millions of cubic metres)*			
Gross production – year	**3,275**	3,996	3,839	4,283	4,538
– per day	**8.9**	11.0	10.5	11.7	12.4
Net production – year	**2,307**	2,854	2,781	3,103	3,327
– per day	**6.3**	7.8	7.6	8.5	9.1
Sales – year	**3,418**	4,116	3,965	4,433	4,962
– per day	**9.3**	11.3	10.9	12.1	12.9
Net reserves	**50,400**	51,900	60,600	59,200	56,300

Wells Completed	**1980**		1979		1978		1977		1976	
Exploratory	**Gross**	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
– Oil	**79**	**41**	17	9	4	2	1	1	3	2
– Gas	**48**	**27**	24	13	14	7	19	12	17	10
– Dry	**103**	**55**	85	42	41	21	30	20	20	8
Development										
– Oil	**96**	**36**	43	11	41	17	38	22	14	10
– Gas	**14**	**1**	25	7	54	25	67	41	53	19
– Dry	**14**	**7**	3	1	21	17	18	12	17	10
Total	**354**	**167**	197	83	175	89	173	108	124	59
Wells (bore holes) capable of producing at year-end	**6,649**	**1,631**	6,646	1,578	6,588	1,546	6,546	1,499	6,407	1,437
Land Position				*(millions of hectares)*						
Crown Reservations and Permits										
Non-producing	**31.9**	**9.1**	34.0	10.4	39.6	9.4	42.7	8.5	33.9	8.8
Leases										
Non-producing	**2.6**	**1.7**	2.1	1.2	1.8	1.1	2.4	1.2	1.8	1.1
Producing	**0.9**	**0.4**	0.9	0.4	0.8	0.5	0.8	0.4	0.7	0.4
Total	**35.4**	**11.2**	37.0	12.0	42.2	11.0	45.9	10.1	36.4	10.3

	1980	1979	1978	1977	1976
Crude Oil Processed	*(thousands of cubic metres per day)*				
Point Tupper, Nova Scotia	**2.9** (2)	9.0	7.5	10.5	7.3
Montreal, Quebec	**10.3**	9.7	10.3	11.5	10.2
Clarkson, Ontario	**10.8**	9.3	10.0	11.1	9.7
Moose Jaw, Saskatchewan	**0.5**	1.2	0.6	1.0	1.0
Calgary, Alberta	**0.9**	1.4	1.2	1.2	1.1
Edmonton, Alberta	**12.5**	12.3	11.7	12.1	10.3
Kamloops, British Columbia	**1.5**	1.4	1.4	1.4	1.3
Port Moody, British Columbia	**6.1**	6.1	5.2	5.1	5.8
Processed by others for Gulf Canada	**0.6**	0.2	—	—	0.2
Total	**46.1**	50.6	47.9	53.9	46.9
Per cent of daily capacity utilized	**88%**	82%	78%	89%	78%
Refined Product Sales	*(thousands of cubic metres per day)*				
Motor gasolines	**15.7**	15.6	15.3	15.4	14.5
Middle distillates	**12.2**	12.4	11.9	12.5	11.6
Other	**14.8** (3)	14.9	15.6	17.5	15.6
Total	**42.7**	42.9	42.8	45.4	41.7
	(millions of kilograms per day)				
Chemicals	**1.3** (3)	1.4	1.3	1.2	1.1
Service Stations at Year-end	**2,716**	2,932	3,178	3,759	3,884
Employees at Year-end	**10,914**	10,400	10,604	11,149	11,088
Total Wages and Salaries *(millions)*	**$275**	$240	$222	$207	$187

(1) Excludes synthetic crude production and reserves.
(2) Refinery shut down in July, 1980 and mothballed.
(3) Includes sale of feedstocks to Varennes plant sold to Petromont after October 1, 1980; chemical sales after that date exclude ethylene sales from the Varennes plant.

Directors

Seated, left: Alfred Powis, J.L. Stoik, J.C. Phillips, Kathleen M. Richardson, Gérard Plourde. Standing, left: W.M. Winterton, secretary; L.P. Blaser, J.D. Allan, C.D. Shepard, R.G. Rogers, E.F. Crease, E.H. Crawford, D.S.R. Leighton, J.E. Lee, W.H. Young.

J.D. Allan
President, Stelco Inc., Toronto, Ontario. Director: CIL Inc., The Royal Trust Company; Royal Trustco Limited; Rockwell International of Canada, Ltd.

L.P. Blaser
President, Gulf Canada Products Company, Toronto, Ontario (Retired, February 28, 1981). Director: Interprovincial Pipe Line Ltd.; Trans Mountain Pipe Line Company Ltd.; Alberta Products Pipe Line Ltd.

E.H. Crawford
President, The Canada Life Assurance Company, Toronto, Ontario. Director: Canadian Imperial Bank of Commerce; Canadian Enterprise Development Corporation Limited; Interprovincial Pipe Line Ltd.; Lakehead Pipe Line Company, Inc.; Moore Corporation Limited.

E.F. Crease
Chairman of the board, Alfred J. Bell & Grant Limited, Halifax, Nova Scotia. Director: Canada Permanent Mortgage Corporation; Canada Permanent Trust Company.

J.E. Lee
President, Gulf Oil Corporation, Pittsburgh, Pennsylvania. Director: Joy Manufacturing Company; Pittsburgh International Finance Corporation; Pittsburgh National Corporation.

D.S.R. Leighton
Director, Banff Centre, Banff, Alberta. Director: Standard Brands Limited; John Wiley and Sons Limited; Canadian Appliance Manufacturing Co. Ltd.; G.S.W. Inc.; Rio Algom Limited; Lornex Mines, Inc.; Scott's Hospitality, Inc.

J.C. Phillips, Q.C.
Chairman of the board, Gulf Canada Limited, Toronto, Ontario. Director: Bank of Nova Scotia; Canada Life Assurance Company.

Gérard Plourde
Chairman of the board, UAP Inc., Montreal, Quebec. Director: Alliance Compagnie; Bell Canada; The Molson Companies Limited; Northern Telecom Ltd.; Rolland Paper Company Limited; Steinberg's Limited; The Toronto-Dominion Bank.

Alfred Powis
Chairman of the board and president, Noranda Mines Limited, Toronto, Ontario. Director: British Columbia Forest Products Limited; Brunswick Smelting and Mining Corporation Limited; Canadian Imperial Bank of Commerce; Brenda Mines Limited; Placer Development Limited; Simpsons-Sears Limited; Sun Life Assurance Company of Canada; Kerr Addison Mines Limited.

Kathleen M. Richardson
Director, James Richardson & Sons, Limited, Winnipeg, Manitoba. Director: Sun Life Assurance Company of Canada.

R.G. Rogers
Chairman of the board, Crown Zellerbach Canada Limited, Vancouver, British Columbia. Director: Canadian Imperial Bank of Commerce; Genstar Limited; Hilton Canada Limited; Rockwell International of Canada, Ltd.

C.D. Shepard
Ottawa, Ontario.

J.L. Stoik
President and chief executive officer, Gulf Canada Limited, Toronto, Ontario. Director: The Toronto-Dominion Bank.

W.H. Young
President, The Hamilton Group Limited; Burlington, Ontario. Director: Stelco Inc.; Harding Carpets Limited; Gore Mutual Insurance Company; National Trust Company Limited; Drummond, McCall & Co. Ltd.

Beverley Matthews, Q.C.
Director Emeritus, Toronto, Ontario.

Officers
Gulf Canada Limited

Left: W.M. Winterton, J.L. Stoik, J.C. Phillips, C.G. Walker, R.E. Harris, R.C. Beal, L.G. Dodd, E.E. Walker, W.H. Burkhiser.

J.L. Stoik,
President and chief executive officer.

J.C. Phillips, Q.C.,
Chairman of the board.

R.C. Beal,
Vice-president, responsible for New Business Development and Research.

W.H. Burkhiser,
Vice-president and treasurer.

L.G. Dodd,
Vice-president and controller.

R.E. Harris,
Vice-president, responsible for Human Resources and Realty.

C.G. Walker,
Vice-president, responsible for Public Affairs.

E.E. Walker,
Vice-president, responsible for Corporate Planning.

W.M. Winterton,
Vice-president, general counsel and secretary.

Officers
Gulf Canada Products Company

Left: K.C. Reeves, M.P. Peterson, W.H. Griffin, R.T. Brown, L.P. Blaser, W.J. Hindson, J.D. DeGrandis, C.W. Fitzwilliam, R.J. Mayo, Tats Matsushita.

R.T. Brown,
President.

J.D. DeGrandis,
Senior vice-president, responsible for Planning and Control.

W.H. Griffin,
Senior vice-president, responsible for Manufacturing, Marketing, Supply and Distribution and Logistics.

C.W. Fitzwilliam,
Vice-president, Control.

W.J. Hindson,
Vice-president, Supply and Distribution.

T. Matsushita,
Vice-president, Planning.

R.J. Mayo,
Vice-president, Logistics.

M.P. Peterson,
Vice-president, Marketing.

K.C. Reeves,
Vice-president, Manufacturing.

Officers
Gulf Canada Resources Inc.

Left: D.R. Motyka, Michael Bregazzi, E.M. Lakusta, S.K. McWalter, R.H. Carlyle, C.K. Caldwell. Missing: T.B. Simms.

S.K. McWalter,
President.

R.H. Carlyle,
Senior vice-president, responsible for Exploration.

Michael Bregazzi,
Vice-president, New Energy Resources.

C.K. Caldwell,
Vice-president, Exploration Operations.

D.R. Motyka,
Vice-president, Production Operations.

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Vice-president, Finance and Planning.

Gulf Canada Limited

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M5H 3R6

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Plants: Montreal East and Shawinigan, Quebec

Accounting and Data Processing Centres
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Research and Development Centre
Sheridan Park, Ontario

Exploration/Production Offices
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Operated gas plants: Baptiste, Bashaw West, Buffalo Lake North, Gilby, Hanna, Morrin-Ghost Pine, Nevis, North Sibbald, Pincher Creek, Rimbey, Strachan and Swalwell, Alberta

Pipelines
Operated pipelines: Alberta Products, Gulf Alberta, Gulf Saskatchewan, Rimbey, Saskatoon, Shawinigan and Valley

Refineries
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Asphalt Plants
Moose Jaw, Saskatchewan; Calgary, Alberta

Principal Affiliates
(Subsidiaries-wholly owned)

COMMERCIAL ALCOHOLS LIMITED
Head Office: Montreal, Quebec
President: W.A. Rogers

GULF CANADA PRODUCTS COMPANY
(A division of Gulf Canada Limited)
Head Office: 800 Bay Street,
Toronto, Ontario M5S 1Y8
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**R.T. Brown, Executive vice-president
J.D. DeGrandis, Senior vice-president
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M.P. Peterson, Vice-president
K.C. Reeves, Vice-president
G.E. Bell, Secretary

*Retired February 28, 1981.
**Appointed Executive vice-president January 1, 1981. Succeeded L.P. Blaser as President March 1, 1981.

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R.H. Carlyle, Senior vice-president
M. Bregazzi, Vice-president
C.K. Caldwell, Vice-president
D.R. Motyka, Vice-president
T.B. Simms, Vice-president and treasurer
G.A. Holland, Secretary

SERVICO LIMITED
Head Office: Quebec, Quebec
President: M.P. Peterson

SUPERIOR PROPANE LIMITED
Head Office: Toronto, Ontario
President: A.L. Goerk

PRINCIPAL INVESTMENTS NOT CONSOLIDATED

Company	Percentage ownership
Alberta Products Pipe Line Ltd.	40.00
Canada Systems Group Limited	33.33
Interprovincial Pipe Line Limited	7.01
Montreal Pipe Line Company Limited	16.00
Peace Pipe Line Ltd.	12.70
Petromont Inc. (partnership)	49.00
Rimbey Pipe Line Co. Ltd.	40.40
Trans Mountain Pipe Line Company Limited	8.57
Trans-Northern Pipe Line Company	33.33

Registrar
Canada Permanent Trust Company, Toronto

Transfer Agents
Canada Permanent Trust Company—Vancouver, Calgary, Regina, Winnipeg, Toronto, Montreal, Saint John, New Brunswick; Charlottetown, Halifax, St. John's, Newfoundland

Registrar and Transfer Company —New York

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THE EAST NEWFOUNDLAND BASIN:

Impact On Gulf Canada Ltd.

ROBERT MOFFITT
W. CAMPBELL GLASS, C.F.A.
JOHN R. S. PEPPERELL

JULY 1980

A great deal of confusion and speculation exists regarding the East Newfoundland Basin, and more specifically its impact on Gulf Canada Ltd. No one, including ourselves, can answer with certainty the question of what is there or what it is worth. While sufficient data will become available over time to narrow and eventually close the gap between reality and expectation, some methodology is currently required to translate the developing reality into a market value.

Simply stated therefore, our objective was to determine some benchmarks of value for Gulf Canada's shares based on an appraisal of its assets in the East Newfoundland Basin and its other profit centers. These parameters could then serve as a basis for investment decisions and/or discussions concerning a "proper" value for the company.

CONTENTS

I SUMMARY & CONCLUSIONS

A) Portfolio Strategy

Our *Energy Unit's* overriding conclusion is that the East Newfoundland Basin and the Jeanne D'Arc Sub-Basin rank extremely high on the list of promising oil ventures as measured on a world-wide basis.

After what we believe to have been a careful examination of the physical and economic parameters associated with the Basin's exploitation, one word seems to us to be descriptive of the opportunity that is available to the participants: exceptional.

Notwithstanding our optimism concerning the economic prospects for the area, we are conscious of the fact that its potential is not open-ended.

(i) As is described in this report, we believe that the investor should acknowledge that governments will find a way to encroach on the future cash flow stream that is normally considered to be the preserve of the developers. Indeed, we fully expect that governments will engineer a fiscal regime that will place a limitation on the participants' share of the eventual economic rewards.

(ii) Additionally, and as described later, there is an obvious limitation to the volumetric additions to reserves that might realistically be expected to be discovered in each structure and, in turn, over the whole basin.

(iii) Finally, the necessity of calculating present values forces a stance of responsibility when measuring increments to asset values due to possible future events.

We expect the stock market to wrestle with the "exceptional" implications associated with exploiting this basin while simultaneously attempting to give due recognition to the foregoing pragmatic cautionary considerations. To us, this is a stage that is supercharged with elements that will lead to market excesses — in both directions!

Indeed, one of the *Energy Unit's* fundamental conclusions pertaining to the East Newfoundland Basin is that the stock market will, over the course of the exploitation phase, go through periods when unjustifiable premiums are attached to the share prices of the participants which will be followed by periods of equally unjustifiable discounts. Basically, we expect a singularly volatile market for the shares of Gulf Canada, for years to come.

If the investor accepts the proposition that the stock market will grossly overreact to good drillhole (and other) news on the upside, and also grossly overreact to negative drillhole news on the downside, then a sensible investment strategy with respect to Gulf Canada could include the following three precepts.

(i) A <u>moderate</u> core position should be established and maintained at all times. We recommend that the core position be 50% of the TSE weight which implies a portfolio weighting of 1½%.

For portfolios that do not now have a position in Gulf, we recommend that it be established when the price of Gulf shares is close to our "Basic Value" of $27.50/share (see Table 1).

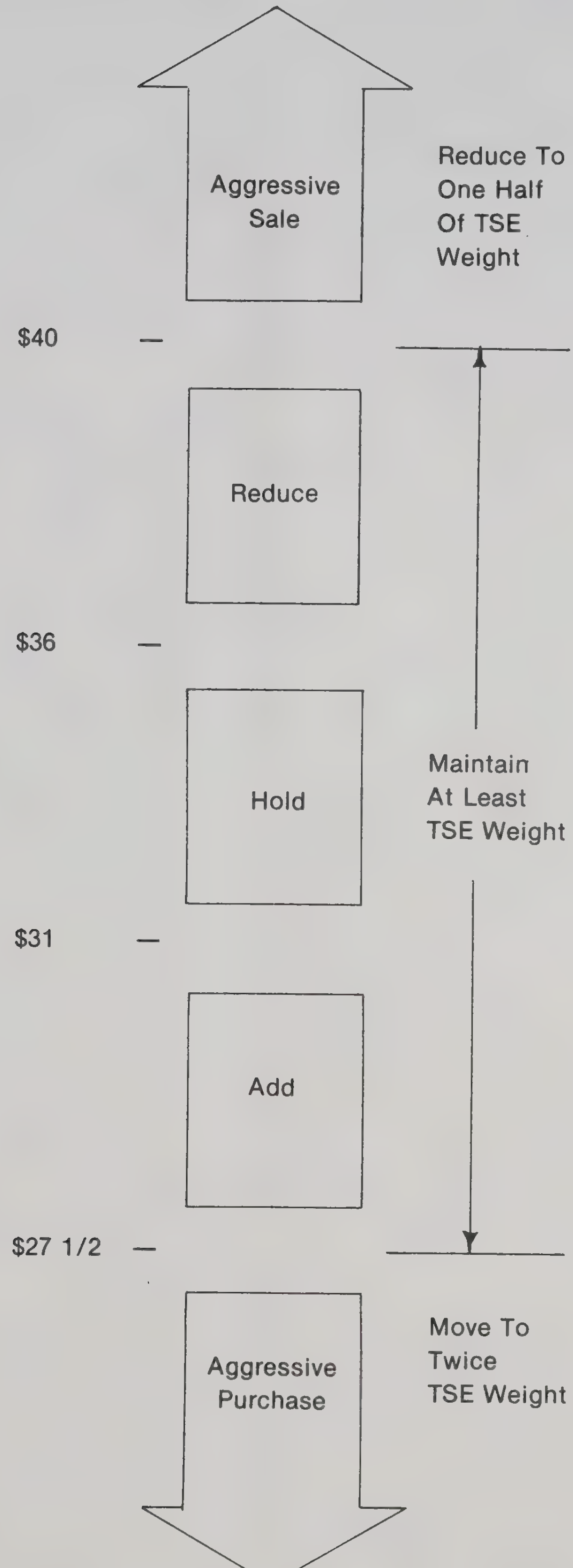
(ii) A significantly overweighted position should be established during periods when Gulf's share price is below our "Basic Value". (In that our current "Basic Value" for Gulf is $27.50/share, we do not recommend accumulation at this time.)

Thus, during periods when Gulf's shares are digesting temporary negative news, we recommend that portfolio positions be increased to at least twice the TSE weight (i.e. a 6% portfolio weighting).

(iii) After setting aside the core position of 1½% as in (a) above, the portfolio should consider <u>all</u> of the balance of the position (4½%) to be available for trading once the market moves to the region of a "super premium". We define a "super premium" as 130% of our "Basic Value" and would mean trading out of Gulf at $36.00/share or above.

Ideally, a portfolio would gradually liquidate its entire 4½% weighting of its trading position of Gulf in the "super premium" region as indicated by the chart on page 5.

GULF CANADA LTD.
PORTFOLIO STRATEGY



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B) The Estimated "Basic Value" Of Gulf Canada Ltd.

Table I presents our estimate of the "Basic Value" of Gulf Canada which was referred to on page 4. The "Basic Value" is meant to be the fulcrum around which the investor can make buy/sell decisions. It reflects, to the best of our ability, a realistic assessment of both fact and expectations. In our opinion, it is not an amount that requires an "everything-has-to-go-right" scenario in order to support it.

We have also shown in Table I our assessment of what we consider to be the realistic upside on Gulf's various ventures. There are definite overtones of speculation included in this amount. Indeed, in order to support our "upside" values, it would be necessary to envision a highly favourable confluence of physical, governmental and economic elements. Although such a set of conditions is not impossible, it is, nonetheless, a long way from assured.

TABLE I

	Range Of Values: $/Share	
	"Basic Value"	"Upside Value"
Refining, Marketing, Petrochemicals Plus Conventional Exploration and Production in Western Canada	$11.00	$15.75
Syncrude & Heavy Oil	0.75	1.10
Beaufort	2.20	6.60
Mackenzie Delta and High Arctic	1.05	2.10
Labrador Shelf	0.65	4.15
East Newfoundland Basin	11.85	16.60
	$27.50	$46.30

(i) The refining, marketing and petrochemical components of Gulf, together with the value of its conventional exploration and production involvement in Western Canada were appraised on the basis of estimated asset values.

Specifically, the refining, marketing and petrochemical assets were assigned their book values as at December 31, 1979. Crude and natural gas liquids were valued at $3.10/bbl, natural gas at 47¢/mcf and land holdings at $100.00/acre (Alberta), $75.00/acre (B.C.) and $40.00/acre (Saskatchewan).

After adding the working capital and deducting all of the non-current liabilities, a total asset value of $15.75/share is derived as being representative of Gulf's conventional activities.

In our opinion, an investor would be on relatively safe ground by including 70% of this conventional asset value or approximately $11.00/share in "Basic Value". The "Upside Value" includes these assets at 100% of the estimated value, i.e. $15.75/share.

(ii) Gulf's 13.4% interest in Syncrude plus its other various interests in heavy oil and bitumen recovery projects was assessed in our "Basic Value" at $0.75 per share. This amount is representative of sales of 20,000 b/d, net to Gulf, for 25 years using a net profit per barrel of $1.50 escalated at 10% per year. (This stream of net profits was discounted at 15% to arrive at a present value.)

For our "Upside Value", we arbitrarily increased Gulf's net production by 10,000 b/d under the assumption that a meaningful incentive program will be instituted to encourage the development of heavy oil projects. This adjustment results in an "Upside Value" of $1.10 per share.

(iii) The "Basic Value" of Gulf's Beaufort Sea involvement is estimated at $2.20 per share. This is based upon an estimated reserve addition of 125 million barrels (it is not inconceivable that Kopanoar alone could make such a contribution) and a present value of $4.00 per barrel. In our opinion, both of the foregoing critical statistics are highly supportable.

In our "Upside Value" as it pertains to the Beaufort, the $6.60 per share assumes reserve additions of 250 million barrels while using a present value of $6.00 per barrel. Although we consider this case to have credibility, we feel that it is approaching the region of undue speculation.

(iv) The Mackenzie Delta and High Arctic valuation of $1.05 per share is based on the assumption that gas discoveries (net to Gulf) in the amount of 3.0 tcf are reasonably assured

 ...continued

(included are 1.3 tcf currently proven in the Mackenzie Delta). We have placed a present value of $0.08 per mcf on these reserves.

For the "Upside Value" ($2.10 per share) we have arbitrarily doubled the present value of the reserves to $0.16 per mcf which reflects the possible economics if deliveries commence in the early 1990's.

We acknowledge that recognition has not been given to the possibility of oil discoveries in this region even though such an event is within the range of realistic expectations.

(v) The Labrador Shelf is clearly highly speculative for both the oil industry and the investor. The potential is sizeable. But, as the combined knowledge of the physical and economic parameters of the region is so limited, it forces the adoption of a conservative appraisal.

In our assessment of the "Basic Value" of Gulf's 20% interest in The Labrador Group, we concluded that a sufficiently high probability of discoveries exists to warrant the inclusion of 100 million barrels of additional reserves net to Gulf. However, the lack of conclusive evidence respecting possible productivity from this region causes us to limit the present value of the possible/probable 100 million barrels to $1.50 per barrel. The contribution to Gulf's "Basic Value" has therefore been placed at $0.65 per share.

The "Upside Value" to Gulf from the Labrador Shelf (given the current state of knowledge) might reasonably be expected to be as much as 25% of the value of the East Newfoundland Basin. On this basis, an upside of $4.15 per share might be considered appropriate.

(vi) As summarized in the next section, we estimate the "Basic Value" and "Upside Value" of Gulf's interests in the East Newfoundland Basin to be $11.85 and $16.60 respectively.

...continued

C) The Economics Of The East Newfoundland Basin

As indicated below we have assigned $11.85 per share to Gulf's "Basic Value" and $16.60 per share to the company's "Upside Value" for its interests in the East Newfoundland Basin. The make-up of this valuation consists of the following:

TABLE 2

	"Basic Value"	"Upside Value"
Hibernia	$ 5.35	$ 8.33
Ben Nevis	2.27	3.28
Structures C, D & E or Land Inventory Value	4.23	4.99
	$11.85	$16.60

(i) Hibernia's value to Gulf is estimated at $5.35 per share as expressed in current dollars. This statistic was derived from our Base Case (see pages 11 to 18 and appendix) which includes the following within its list of parameters and conclusions.

- 1 billion barrels of recoverable reserves
- Flow rate at peak (1989) of 400,000 b/d
- Initial production (1985) of 100,000 b/d
- Total gross capital costs of $6.0 billion
- Total net (after-tax) capital costs of $2.7 billion
- Reserve life index of 16 years
- Present value of oil over life of field at $8.12 per barrel
- Discount rate applied to future cash flow stream of 15%
- DCF rate of return of 55.8%.

(ii) Ben Nevis was assumed to track the economics of our Case 'A' that was prepared during the process of evaluating Hibernia. The principal difference between Case 'A' and the Base Case lies in the variance in recoverable reserves. That is, the Base Case assumed 1.0 billion barrels while Case 'A' assumed 750 million barrels.

Ben Nevis was assumed to commence production three years after the initial production from Hibernia, i.e. in 1988.

The "Basic Value" assigned to Ben Nevis was $2.27 per share.

(iii) In accordance with our conviction that the East Newfoundland Basin will eventually prove to be a major producing region, we feel justified in assigning a value to Gulf's land inventory. The method chosen was to assume that 3 separate fields, of 500 million barrels of recoverable reserves each, will come on-stream sequentially commencing in 1990. (The material for appraising these fields was developed during the appraisal process of Hibernia.)

The amount added to Gulf's "Basic Value" due to bringing on structures C, D & E is $4.23 per share.

(iv) Our "Upside Value" to Gulf from the East Newfoundland Basin was placed at $16.60 per share. This reflects the following adjustments from the "Basic Value" calculations.

- Hibernia was assumed to have recoverable reserves of 1.5 billion barrels versus 1.0 billion.

- Ben Nevis was assumed to have 1.0 billion barrels versus 750 million.

- Structures C, D & E were each assumed to come on-stream 2 years in advance of the timing schedule used in our "Basic Value" determinations.

D) The Economics Of Hibernia

The value of Hibernia, separately, to Gulf is clearly crucial to the determination of Gulf's overall "Basic Value" and/or "Upside Value".

Our investigations have led us to conclude that the realistic range of probabilities as to recoverable reserves includes a case each for 750 million barrels, 1.0 billion barrels, 1.25 billion barrels and 1.5 billion barrels.

Naturally, each of the cases (as built around recoverable reserves) has its individual set of physical and economic parameters and a full discussion of each could be burdensome to the reader. Accordingly, we have shown below only those statistics that pertain to the final value to Gulf as determined by our evaluation of the various cases. The data below refers to Gulf's per share interest in Hibernia's estimated net cash flow after taxes and capital recovery and discounted at 15% over the life of the project.

TABLE 3

		Value To Gulf $/Share
Case A:	0.750 Billion Barrels Recoverable	$3.73
Base Case:	1.00 Billion Barrels Recoverable	5.35
Case B:	1.25 Billion Barrels Recoverable	6.90
Case C:	1.50 Billion Barrels Recoverable	8.33

As was mentioned previously, we have used the 1.0 billion barrel case for our "Basic Value" and the 1.5 billion barrel case for our "Upside Value".

II ANALYSIS

A) Overview Of Geological Setting

The geology of the East Newfoundland Basin and the Jeanne D'Arc Sub-Basin is the result of several separate tectonic, depositional and erosional occurrences.

As a point of departure for the purposes of this study, the reader should understand that in pre-Jurassic time (about 200 million years ago) Newfoundland and Europe were connected as one land mass.

During the Jurassic Period, the first relevant tectonic plate movement occurred. This major upheaval resulted in the tearing away of Europe from what is now Newfoundland. As is usual with similar dramatic wrenchings of the Earth's crust (as caused by plate movements), the peripheral zones underwent exceptionally forceful stresses. One of the manifestations of the stress phenomena was the formation (over extended time) of a series of uplifted blocks (horsts) and downshifted blocks (grabens). These formations (structures) are one of the causes for the eventual entrapment of hydrocarbons in the continental pull-apart zones of off-shore Newfoundland.

During, and subsequent to, the early Jurassic Period of block formation, the ocean that covered what is now the East Newfoundland Basin was essentially sub-tropical in nature. Accordingly, massive amounts of marine organic material were generated and eventually deposited on the ocean floor. This occurrence was the first step in the eventual creation of Hibernia's hydrocarbons.

Fortuitously, the continent was undergoing erosional influences throughout the periods that followed the major plate movement and block formation. This resulted in the deposition of material over the structural formations.

As the ancient shoreline was (and is) in a state of constant movement in an east-west direction, the material that eventually became draped over the block formations in the East Newfoundland Basin underwent changes in composition. That is, beds of clay and silt were deposited when the shoreline was at its most westerly position, and the coarse material such as sand was deposited when the shoreline moved towards its more easterly extremities. The result was a stratification of several layers of these types of sediment.

...continued

The clays and silts, with the addition of temperature and pressure, etc., eventually were transformed into shale while the coarser material eventually was transformed into sandstone.

The combination of abundant organic material as deposited simultaneously with the sequential deposition of clays and silts provided the basic elements needed for the creation of shale source rocks.

Over the 100+ million years of deposition (from early Jurassic through Cretaceous) the pressure of the various beds of sediments eventually resulted in an orderly geochemical influence which had as its end product the creation of liquid hydrocarbons in the shale beds.

The final fortuitous event forces a recall of the fact that the coarse sands were also sequentially being draped over the horst formations and lying intermingled with the shale sections. This, plus the simple, but totally necessary differential contour of the sandstone sections, resulted in the formation of the reservoir rock plus the trapping mechanism.

The foregoing is acknowledged to be grossly over-simplified and it might result in the erroneous conclusion that the location of structures such as Hibernia is a relatively commonplace application of existing technology. Obviously, the geology of this basin is extremely complicated. Additionally, each relatively pronounced structure such as Hibernia underwent extreme "internal" faulting and shifting which further complicates the assessment process. (The aspect of "internal" complexities explains, to some extent, the differential findings of the three Hibernia exploration wells.)

Hibernia and Ben Nevis are believed to be but two of many reasonably similar geological features that have been distributed in the East Newfoundland Basin. And, as the presence of crude oil in exceptionally large volumes has been indicated by Hibernia and in all likelihood, Ben Nevis, it would only be consistent with experience elsewhere in the world to expect that, over time, several other productive structures will be located.

B) Geological And Physical Parameters Used In Determining Recoverable Reserves For Hibernia

Summary Comments

As can be seen by Table 4 on page 16, our Base Case assumes that recoverable reserves amount to 1.0 billion barrels. The case with the lowest amount of recoverable reserves is Case 'A' at 750 million barrels, and the highest is Case 'C' at 1.5 billion barrels.

The reader might question the credibility of presenting cases with such a wide variance in recoverable reserves. We sympathize with those who wish to question the range but we suggest that the determination of the recoverable reserves in all cases can be supported by actual experience elsewhere in the world. In other words, the investor can rest assured that a 100% swing in recoverable reserves (from 750 million to 1.5 billion) definitely lies within the spectrum of realistic probabilities.

Explanation Of Variables

The area of closure of 18,000 acres represents our understanding of the probable areal extent of the productive formations as announced by the operator in 1979.

Because Hibernia is believed to be a combination stratigraphic-structural anomaly, it is entirely possible that our estimate of 18,000 acres will eventually prove to be either too large or too small. Although the magnitude of the eventual "shrinkage" or "extension" from 18,000 acres is a matter of uncertainty at this time, we have elected to consider 18,000 acres as productive in all of our economic cases.

The amount of net pay is one of the most crucial variables at this stage in the appraisal process.

In that the "internal" geology of the structure includes considerable faulting and shifting, there will clearly be significant variations in the net pay from section-to-section within the structure. Additionally, as the productive sands are believed to pinch-out against shales in the north/south extremities, a reduction in average net pay should occur towards the periphery of the structure.

...continued

Naturally, until many more wells are drilled, an educated guess is all that can be employed in estimating the eventual average net pay. As can be seen by Table 4, we have used an average net pay of 245 feet in our Base Case. (This compares to 307 feet as indicated by tests on Well #P-15.)

It is our opinion that it is technically justifiable and wholly reasonable to include in this study an alternate case that assumes as much as 1.5 billion barrels of recoverable reserves as per Case 'C'. While several combinations of net pay, porosity, oil saturation, etc. could provide this result, the method chosen was to assume average net pay of 340 feet. Once one has accounted for the increased governmental encroachment on the cash flow stream that would be derived from a 1.5+ billion barrel structure, however an inclusion of a case beyond 1.5 billion barrels becomes, in our view, primarily of academic interest.

The average porosity of the reservoir formations used in all cases in this study was held constant at 15%.

We are convinced that the quality of the reservoir rocks is excellent. Accordingly, we feel that the average porosity will be not less than 15%. (For comparative purposes, we remind readers that the main Cardium zones in Pembina have a porosity of about 13% and these formations are not viewed as being of particularly exceptional quality.)

The oil saturation as a percent of pore space was assumed to be 70% in all of our economic cases. This percentage is representative of Cretaceous reservoir formations in Alberta which have a range of between 65% and 90%.

The recovery factor of 35% is representative of the expectations for most North Sea fields. In our opinion, 35% is an accurate reflection of a minimum recovery under primary drive. Pressure maintenance through extensive water flooding would raise the overall recovery rate.

The shrinkage factor used in our economic cases of 15% is a relatively standard co-efficient for crude oil found at depths comparable to Hibernia and that are of similar API^{o} gravity.

TABLE 4

	Base Case	Alternate Case 'A'	Alternate Case 'B'	Alternate Case 'C'
Areal Closure (acres)	18,000	18,000	18,000	18,000
Feet of Net Pay	245	170	285	340
Porosity	15%	15%	15%	15%
Oil Saturation	70%	70%	70%	70%
Oil-In-Place (bln)	3.6	2.5	4.2	5.0
Recovery Factor	35%	35%	35%	35%
Shrinkage Factor	15%	15%	15%	15%
Recoverable Reserves (bln)	1.0	.750	1.25	1.50

...continued

C) Exploration And Development Drilling And Associated Capital Costs: Hibernia

The drilling schedule for the development of Hibernia assumes that the existing program will be continued into 1981. This would put one more completed hole on the structure by early 1981 in addition to P-15, O-35 and B-08.

A total of 45 wells would be drilled under our estimated exploration and development program. Of the total, 25 would be production wells, 15 would be injection wells and 5 are assumed to be non-productive delineation wells.

The base cost of all wells was assumed to be $65 million, as expressed in 1979 dollars. An annual escalation of 7½% was assumed sufficient to account for inflation for all wells drilled after 1979.

We have assumed that exploration costs will qualify for some form of 'super-depletion' allowance subsequent to 1980. This has been accounted for in the "net" capital cost estimates shown below in Table 5.

We expect that development costs will receive a similar tax treatment to that which was applicable to Syncrude; namely, the use of a "fast write-off". This mechanism permits a 100% deduction of capital outlays from taxable income regardless of its source.

TABLE 5

	Gross Cost	After-Tax Cost
	($ millions)	
Exploration Drilling	$ 866	$ 146
Development Drilling	3,696	1,848
Total	$4,562	$1,994
% Funded by Governments	56%	

D) Production Techniques And
Associated Capital Costs: Hibernia

There are two types of facilities that are potentially viable for producing the Hibernia oil: (a) cement gravity platforms; and, (b) sub-sea completion plus semi-submersible drilling equipment. As environmental considerations will play a large role in the choice between the alternate methods, we have assumed that the relatively mobile sub-sea facilities will be adopted.

Apart from the fact that environmental influences are less for the sub-sea system than for fixed platforms, the sub-sea method has capital cost and cash flow advantages. It should also be recognized that pack ice and icebergs could prevent the use of the immobile cement gravity structure altogether. (Mobil has not yet completed its feasibility studies on the production systems thought to be viable.)

The typical sub-sea production system has a number of producing and injection wells (a "cluster") tied into a single template which, in turn, is connected via risers to a floating "container" for processing and transshipping. We have assumed that all of the wells required for a separate "cluster" will have been drilled before production facilities are installed. A one year lag is assumed for construction of the sub-sea production facilities after drilling has been completed.

The well configuration used in this analysis is 5 producing wells and 3 water and/or gas injection wells per "cluster". This ratio of production to injection holes is consistent with the type of arrangement utilized in the Ninian field which contains approximately 1 billion barrels of recoverable reserves in a reservoir of slightly larger areal extent than Hibernia. We have also assumed that, overall, 5 clusters will be needed. Therefore, 25 producing wells will eventually be distributed over the Hibernia structure.

The flow rates per well for the "clusters" will vary according to the differences in reservoir parameters encountered in the various sections of the prospect. Basically, we feel the net pay per well will vary due to the extensive faulting that has occurred throughout the reservoir. However, we have assumed reasonable continuity of the pay zones through the extent of each separate cluster and therefore have kept the producibility of the wells in each cluster similar.

 ...continued

As the developers are likely to extract the oil as quickly as possible (without damaging the reservoir drive) we have assumed that the first section of the reservoir to be developed will be that which the delineation wells have shown to have the highest productivity. We have also assumed that production per well for each of the 5 different clusters will decrease as the less productive areas of the structure are developed.

For simplicity, the productivity of the different clusters has been assumed to decline at the same rate once they come on stream. No production decline is realized for the first five years of production as the injection wells and the shut-in pressure build-up will serve to keep the reservoir drive at the initial production levels. Production is then assumed to decline at 15% per year for two years and at 10% per year until the recoverable reserves are exhausted.

The only other major facility needed for production is a processing and storage facility. The simplest method of providing this service is a floating "container & processing" unit which is hooked-up to all the templates from a centrally located position. Medium sized tankers are assumed to load directly from this unit.

As icebergs necessitate the burying of pipelines, it is felt tanker transportation is the most viable. Our estimates assume that it is feasible to load and unload 7 days of peak production within a 7 day time period thereby permitting continuous production.

Pack ice, fog and icebergs are expected to prevent continued access to the marine storage "container". Hence we have forecasted 250 stream days per year for the field.

It is expected that the Federal government will initiate a stimulative tax incentive for the development of this field and we have assumed that 50% of the total development outlays will be Federally financed through some form of "fast write-off" allowance (see Table 6).

TABLE 6

	Gross Cost	After-Tax Cost
	($ millions)	
Production and Marine Facilities	$1,471	$ 736
% Funded by Governments	50%	

TABLE 7

Summary Of Statistics For Base Case

Total number of wells drilled		45
Total number of production wells		25
Number of separate producing "clusters"		5
Capital cost of sub-sea production system		$1.2 billion
Capital cost of marine storage & processing		$ .3 billion
Number of stream days per calendar year		250
Flow rate at peak from "Cluster" #1	(1985)	100,000 b/d
Flow rate at peak from "Cluster" #2	(1986)	90,000 b/d
Flow rate at peak from "Cluster" #3	(1987)	80,000 b/d
Flow rate at peak from "Cluster" #4	(1988)	70,000 b/d
Flow rate at peak from "Cluster" #5	(1989)	60,000 b/d
Peak production from field	(1989)	400,000 b/d
Total oil recovered		1.0 bil bbls
Life of field		16 years

...continued

E) Fiscal Regime And Sharing Of The Economic Rewards: Hibernia

One of the most rigid conclusions that we have drawn from our examination of the various components of subject material relating to oil off the East Coast is that the Federal and Provincial governments will institute mechanisms to ensure that their respective treasuries will derive substantial economic benefits from the successful exploitation of any discoveries.

Although the jurisdictional dispute as to ownership of off-shore resources has not yet been settled, it appears to us that the combined governmental share of the gross cash flow generated from a "ring-fenced" Hibernia will approximate 70% of the total amount.

To us, it is almost irrelevant which government is eventually granted ownership rights. We have considered their positions to be interchangeable as viewed from the perspective of the corporate developers.

However, for purposes of illustration, we have assumed that the Province of Newfoundland will eventually be granted ownership rights to off-shore oil and we have therefore assumed that Newfoundland's Petroleum and Natural Gas Act will come into force. According to this legislation, the following vehicles would gather Newfoundland's share of Hibernia's undiscounted gross cash flow as estimated by our *Energy Unit* (see Table 8).

The data below reflects the estimated economics of our Base Case which assumed recoverable reserves of 1.0 billion barrels (see appendix).

TABLE 8

	$ Billions	% Of Total Gross Cash Flow
Royalty @ 10%	9.25	
Newfoundland and Labrador Petroleum Corporation (NLPC) 40% Working Interest*	30.99	
	40.24	46.40%

*NLPC assumed not liable for federal income taxes

We have arbitrarily assumed in this study that Newfoundland will not impose an income tax on the "ring-fenced" profits of Hibernia. This reflects our view that Newfoundland must act responsibly when carving out its share and will not take a position that will impede or deter development of off-shore resources via the route of exacting an excessive rent.

However, it is worth noting that the Petroleum and Natural Gas Act of Newfoundland provides for a sliding scale of royalties above the basic 10%. In effect, this mechanism limits the amount that might be earned by corporate developers in the event of an exceptionally productive discovery.

In that we have assumed that Newfoundland will eventually own the resources, it follows that the Federal Government's share of the cash flow from Hibernia would be limited to the application of an income tax on the corporate developers' profits.

Accordingly, the Federal position is shown below using the data derived from our Base Case.

TABLE 9

	$ Billions	% Of Total Gross Cash Flow
Federal Income Tax at 36% of Corporate Developers' Pre-Tax Profits	18.73	21.60%

Apart from the application of a basic income tax as above, we believe that the Federal Government could successfully legislate a "surtax" on the profits that might be earned from exceptionally prolific discoveries. The recognition of this aspect is fundamental to our conviction that it would be imprudent for the investor to speculate about the potential economics of a "superstructure".

After accounting for the share of the cash flow stream that is estimated to be withdrawn by the Federal and Provincial governments, the corporate developers' position is as shown in Table 10.

TABLE 10

	$ Billions	% Of Total Gross Cash Flow
Corporate Developers On A Combined Basis	27.75	32.00%
Gulf Canada Separately	6.94	8.00%

...continued

APPENDIX:

The Base Case In Detail

SCHEDULE OF CRUDE PRICE FORECAST F.O.B. PERSIAN GULF

YEAR	34° CRUDE FOB PERSIAN GULF $US/BBL	PRICE ADJUSTED FOR INFLATION AT 7.5 °/°	PRICE ADJUSTMENT FOR INCREASED 'REAL' VALUE AT 3.0 °/°	ADJUSTED CRUDE PRICE FOF PERSIAN GULF $US/BBL	CONVERSION FACTOR TO CANADIAN DOLLARS	ADJUSTED PRICE IN CANADIAN $ $/BBL
1979						
1980	32.00	32.00		32.00	0.86	37.21
1981		34.40	0.96	35.36	0.88	40.18
1982		36.98	1.95	38.93	0.90	43.25
1983		39.75	2.97	42.72	0.90	47.47
1984		42.74	4.02	46.75	0.90	51.95
1985		45.94	5.10	51.04	0.90	56.71
1986		49.39	6.21	55.60	0.90	61.77
1987		53.09	7.36	60.45	0.90	67.16
1988		57.07	8.54	65.61	0.90	72.90
1989		61.35	9.75	71.10	0.90	79.00
1990		65.95	11.01	76.96	0.90	85.51
1991		70.90	12.30	83.19	0.90	92.44
1992		76.22	13.62	89.84	0.90	99.82
1993		81.93	14.99	96.93	0.90	107.70
1994		88.08	16.40	104.48	0.90	116.09
1995		94.68	17.85	112.54	0.90	125.04
1996		101.79	19.35	121.14	0.90	134.60
1997		109.42	20.89	130.31	0.90	144.79
1998		117.63	22.48	140.10	0.90	155.67
1999		126.45	24.11	150.56	0.90	167.29
2000		135.93	25.80	161.73	0.90	179.70

...continued

SCHEDULE OF FORECAST CRUDE PRICE AT WELLHEAD

YEAR	ADJUSTED PRICE IN CANADIAN $ FOB PERSIAN GULF $/BBL	85 °/° OF TOTAL PRICE $/BBL	ADD BOAT FREIGHT TO HALIFAX LESS FREIGHT TO WELLHEAD $/BBL	ESCALATED FREIGHT AT 7.5 °/°	ADJUSTED BOAT FREIGHT PRICE $/BBL
1979					
1980	37.21	31.63	2.00	2.00	33.63
1981	40.18	34.15	2.00	2.15	36.30
1982	43.25	36.77	2.00	2.31	39.08
1983	47.47	40.35	2.00	2.48	42.83
1984	51.95	44.15	2.00	2.67	46.82
1985	56.71	48.20	2.00	2.87	51.07
1986	61.77	52.51	2.00	3.09	55.59
1987	67.16	57.09	2.00	3.32	60.41
1988	72.90	61.96	2.00	3.57	65.53
1989	79.00	67.15	2.00	3.83	70.99
1990	85.51	72.68	2.00	4.12	76.80
1991	92.44	78.57	2.00	4.43	83.00
1992	99.82	84.85	2.00	4.76	89.61
1993	107.70	91.54	2.00	5.12	96.66
1994	116.09	98.68	2.00	5.50	104.18
1995	125.04	106.29	2.00	5.92	112.20
1996	134.60	114.41	2.00	6.36	120.77
1997	144.79	123.07	2.00	6.84	129.91
1998	155.67	132.32	2.00	7.35	139.67
1999	167.29	142.20	2.00	7.90	150.10
2000	179.70	152.74	2.00	8.50	161.24

SCHEDULE OF PRODUCTION

YEAR	CLUSTER 1 5 WELLS 250 DAYS PER STREAM DAY-MBBLS	CLUSTER 2 5 WELLS 250 DAYS PER STREAM DAY-MBBLS	CLUSTER 3 5 WELLS 250 DAYS PER STREAM DAY-MBBLS	CLUSTER 4 5 WELLS 250 DAYS PER STREAM DAY-MBBLS	CLUSTER 5 5 WELLS 250 DAYS PER STREAM DAY-MBBLS	TOTAL PRODUCTION MMBBLS	CUMULATIVE TOTAL PRODUCTION MMBBLS
1979							
1980							
1981							
1982							
1983							
1984							
1985	20.0					25.0	25.0
1986	20.0	18.0				47.5	72.5
1987	20.0	18.0	16.0			67.5	140.0
1988	20.0	18.0	16.0	14.0		85.0	225.0
1989	20.0	18.0	16.0	14.0	12.0	100.0	325.0
1990	17.0	18.0	16.0	14.0	12.0	96.3	421.3
1991	14.5	15.3	16.0	14.0	12.0	89.7	510.9
1992	13.0	13.0	13.6	14.0	12.0	82.0	592.9
1993	11.7	11.7	11.6	11.9	12.0	73.6	666.5
1994	10.5	10.5	10.4	10.1	10.2	64.7	731.3
1995	9.5	9.5	9.4	9.1	8.7	57.6	788.9
1996	8.5	8.5	8.4	8.2	7.8	51.9	840.8
1997	7.7	7.7	7.6	7.4	7.0	46.7	887.4
1998	6.9	6.9	6.8	6.6	6.3	42.0	929.4
1999	6.2	6.2	6.1	6.0	5.7	37.8	967.2
2000	5.6	5.6	5.5	5.4	5.1	34.0	1001.3
TOTAL	211.1	185.0	159.4	134.7	110.8	1001.3	

SCHEDULE OF GROSS CASH FLOW

YEAR	PRODUCTION MMBBL	WELLHEAD PRICE $/BBL	GROSS REVENUE $MM	10 °/° ROYALTY $MM	GROSS REVENUE AFTER ROYALTY $MM
1979		33.63			
1980		36.30			
1981		39.08			
1982		42.83			
1983		46.82			
1984					
1985	25.0	51.07	1,277	128	1,149
1986	47.5	55.59	2,641	264	2,377
1987	67.5	60.41	4,077	408	3,670
1988	85.0	65.53	5,570	557	5,013
1989	100.0	70.99	7,099	710	6,389
1990	96.3	76.80	7,392	739	6,653
1991	89.7	83.00	7,444	744	6,700
1992	82.0	89.61	7,349	735	6,614
1993	73.6	96.66	7,113	711	6,402
1994	64.7	104.18	6,744	674	6,070
1995	57.6	112.20	6,466	647	5,819
1996	51.9	120.77	6,263	626	5,637
1997	46.7	129.91	6,063	606	5,457
1998	42.0	139.67	5,867	587	5,280
1999	37.8	150.10	5,675	567	5,107
2000	34.0	161.24	5,486	549	4,938
TOTAL	1001.3		92,528	9,253	83,275

SCHEDULE OF CAPITAL COSTS

YEARS	*NUMBER OF WELLS DRILLED*	*BASE COST PER WELL $MM*	*COST ESCALATION PER WELL*	*TOTAL DRILLING COSTS $MM*	*TOTAL TRANSPORTATION PRODUCTION FACILITIES $MM*	*TOTAL CAPITAL $MM*
1979	1	65	65	65		65
1980	3		72	215		215
1981	4		79	315		315
1982	5		87	433		433
1983	8		95	761	100	861
1984	8		105	837	350	1187
1985	10		115	1152	220	1372
1986	4		127	507	242	749
1987	2		139	279	266	545
1988					293	293
TOTAL	45			4562	1471	6033

SCHEDULE OF TAXABLE INCOME *

YEAR	GROSS REVENUE BEFORE ROYALTY $MM	OPERATING COST $/BBL	OPERATING COST $MM	INTEREST EXPENSE $MM	GROSS CASH FLOW OR TAXABLE INCOME $MM	FEDERAL INCOME TAX AT 36 °/° $MM	NET OPERATING CASH FLOW AFTER TAX AND ROYALTIES $MM	NET CASH CAPITAL COSTS $MM	PROJECT NET CASH FLOW YEAR $MM	PROJECT NET CASH FLOW CUMULATIVE $MM
1979		2.00						7	(7)	(7)
1980		2.15						54	(54)	(60)
1981		2.31						63	(63)	(123)
1982		2.48						130	(130)	(253)
1983		2.67		39	(39)	(14)	(25)	404	(429)	(682)
1984		2.87		97	(97)	(35)	(62)	594	(656)	(1,338)
1985	1,277	3.09	77	164	1,036	373	535	686	(151)	(1,488)
1986	2,641	3.32	158	201	2,282	822	1,197	374	822	(666)
1987	4,077	3.57	241		3,837	1,381	2,048	272	1,775	1,109
1988	5,570	3.83	326		5,244	1,888	2,799	147	2,653	3,762
1989	7,099	4.12	412		6,687	2,407	3,570		3,570	7,332
1990	7,392	4.43	427		6,966	2,508	3,719		3,719	11,051
1991	7,444	4.76	427		7,017	2,526	3,747		3,747	14,797
1992	7,349	5.12	420		6,929	2,495	3,700		3,700	18,497
1993	7,113	5.50	405		6,708	2,415	3,582		3,582	22,079
1994	6,744	5.92	383		6,361	2,290	3,397		3,397	25,476
1995	6,466	6.36	367		6,099	2,196	3,257		3,257	28,732
1996	6,263	6.84	355		5,908	2,127	3,155		3,155	31,888
1997	6,063	7.35	343		5,720	2,059	3,055		3,055	34,942
1998	5,867	7.90	332		5,535	1,993	2,956		2,956	37,898
1999	5,675	8.50	321		5,353	1,927	2,859		2,859	40,757
2000	5,486	9.13	311		5,175	1,863	2,764		2,764	43,520
TOTAL	92,528		5,304	501	86,722	31,220	46,250	2,729	43,520	

NET PRESENT VALUE DISCOUNTED AT 15 °/° IN 1981 DOLLARS: 8127.19 MILLION DOLLARS

DCF RATE OF RETURN: 55.81 °/° TOTAL PRODUCTION (MMBBLS): 1001.3

*PRIOR TO ADJUSTMENT REQUIRED TO TAKE ACCOUNT OF TAX EXEMPTION OF NLPC'S 40°/° WORKING INTEREST.